Utility-Scale Solar 2016

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

Authors: Mark Bolinger, Joachim Seel, Kristina Hamachi LaCommare
Lawrence Berkeley National Laboratory

September 2017

Powered by SunShot
U.S. Department of Energy
BERKELEY LAB
LAWRENCE BERKELEY NATIONAL LABORATORY

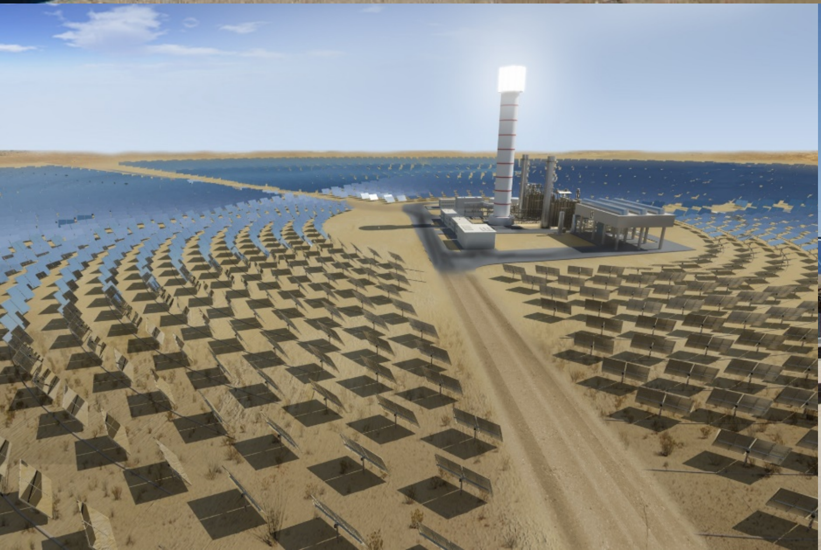


Table of Contents

List of Acronyms i

Executive Summary ii

1. Introduction 1

2. Utility-Scale Photovoltaics (PV).... 5

2.1 Installation and Technology Trends Among the PV Project Population (427 projects, 16,439 MW_{AC}) 6
States with utility-scale PV projects now outnumber those without *6*
Tracking c-Si projects dominate 2016 additions *9*
More PV projects at lower insolation sites, fixed-tilt mount less common in sunny areas *10*
Developers continued to favor larger module arrays relative to inverter capacity *12*

2.2 Installed Project Prices (361 projects, 14,469 MW_{AC}) 14
Median prices fell to \$2.2/W_{AC} (\$1.7/W_{DC}) in 2016 *15*
Tracking projects often command a price premium over fixed-tilt installations *16*
Evidence of economies of scale remains elusive *17*
System prices vary by region *18*

2.3 Operation and Maintenance Costs (30 projects, 546 MW_{AC}) 21

2.4 Capacity Factors (260 projects, 8,733 MW_{AC}) 23
Wide range in capacity factors reflects differences in insolation, tracking, and ILR *23*
More recent project vintages exhibit higher capacity factors *26*
Performance degradation is evident, but is difficult to assess and attribute at the project level *27*

2.5 Power Purchase Agreement (PPA) Prices (189 contracts, 11,677 MW_{AC}) 30
PPA prices have fallen dramatically, in all regions of the country *32*
Solar's largely non-escalating and stable pricing can hedge against fuel price risk *38*

3. Utility-Scale Concentrating Solar Thermal Power (CSP).... 42

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1,781 MW_{AC}) 42

3.2 Installed Project Prices (7 projects, 1,381 MW_{AC}) 43

3.3 Capacity Factors (13 projects, 1,654 MW_{AC}) 45

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1,301 MW_{AC}) 46

4. Conclusions and Future Outlook.... 48

References 50

Data Sources 50

Literature Sources 50

Appendix.... 54

Total PV Population 54

Total CSP Population 54

List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
COD	Commercial Operation Date
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar (Thermal) Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPC	Engineering, Procurement & Construction
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MW	Megawatt(s)
NCF	Net Capacity Factor
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PII	Permitting, Interconnection & Inspection
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
TOD	Time of Delivery

Executive Summary

The utility-scale solar sector—defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar thermal power ("CSP") project that is larger than 5 MW_{AC} in capacity—has led the overall U.S. solar market in terms of installed capacity since 2012. In 2016, the utility-scale sector installed more than 2.5 times as much new capacity as did the residential and commercial sectors combined, and is expected to maintain its market-leading position for at least another five years, driven in part by the December 2015 extension of the 30% federal investment tax credit ("ITC") through 2019. With seven new states having added their first utility-scale solar project in 2016, more than half of all states, representing all regions of the country, are now home to one or more utility-scale solar installations. For the first time ever, solar was the largest source of new U.S. capacity additions in 2016, accounting for 38% of all new capacity added to the grid, ahead of both natural gas and wind (utility-scale solar accounted for 70% of this 38%). This unprecedented and ongoing solar boom makes it difficult—yet more important than ever—to stay abreast of the latest utility-scale market developments and trends.

This report—the fifth edition in an ongoing annual series—is intended to help meet this need, by providing in-depth, annually updated, data-driven analysis of the utility-scale solar project fleet in the United States. Drawing on empirical project-level data from a wide range of sources, this report analyzes not just installed project prices—i.e., the traditional realm of most solar economic analyses—but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects throughout the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are also presented where appropriate.

Some of the more-notable findings from this year's edition include the following:

- ***Installation Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and PPA price data analyzed later. For example, the use of solar tracking devices (overwhelmingly single-axis, east-west tracking—though a few dual-axis tracking projects have come online in Texas in recent years) dominates 2016 installations with nearly 80% of all new capacity. In a reflection of the ongoing geographic expansion of the market beyond California and the high-insolation Southwest, the median long-term insolation level at newly built project sites declined again in 2016. While new fixed-tilt projects are now seen predominantly in less-sunny regions (GHI < 5 $kWh/m^2/day$), tracking projects are increasingly pushing into these same regions. Meanwhile, the median inverter loading ratio—i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating—has stabilized in 2016 at 1.3 for both tracking and fixed-tilt projects.
- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by two-thirds since the 2007-2009 period, to $\$2.2/W_{AC}$ (or $\$1.7/W_{DC}$) for projects completed in 2016. The lowest 20th percentile of projects within our 2016 sample (of 88 PV projects totaling 5,497 MW_{AC}) were priced at or below $\$2.0/W_{AC}$, with the lowest-priced projects around $\$1.5/W_{AC}$. Projects using single-axis trackers had an upfront cost premium

of about \$0.15/W_{AC} compared to fixed-tilt installations. Overall price dispersion across the entire sample and across geographic regions decreased significantly in 2016.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs were in the neighborhood of \$18/kW_{AC}-year, or \$8/MWh, in 2016. These numbers—from an extremely limited sample—include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.
- ***Capacity Factors:*** The cumulative net AC capacity factors of individual projects in a sample of 260 PV projects totaling 8,733 MW_{AC} range widely, from 15.4% to 35.5%, with a sample mean of 25.8%, a median of 26.3%, and a capacity-weighted average of 27.3%. This project-level variation is based on a number of factors, including the strength of the solar resource at the project site, whether the array is mounted at a fixed tilt or on a tracking mechanism, the inverter loading ratio, degradation, and curtailment. Changes in at least the first three of these factors drove mean capacity factors higher from 2010-vintage (at 22.0%) to 2013-vintage (at 26.9%) projects, where they've remained fairly steady among both 2014-vintage (at 26.2%) and 2015-vintage (at 26.5%) projects as an ongoing increase in the prevalence of tracking has been offset by a build-out of lower resource sites. Turning to other technologies, the three CPV projects in our sample have been underperforming relative to similarly situated PV projects and, in at least two cases, ex-ante expectations. Likewise, although several CSP projects in the United States are seemingly matching ex-ante capacity factor expectations, at least three others—each beset by shut-downs of varying duration in 2016—continue to underperform relative to projected long-term, steady-state levels.
- ***PPA Prices:*** Driven by lower installed project prices and improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by \$20-\$30/MWh per year on average from 2006 through 2012, with a smaller price decline of ~\$10/MWh per year evident from 2013 through 2016. Most recent PPAs in our sample—including many outside of California and the Southwest—are priced at or below \$50/MWh levelized (in real 2016 dollars), with a few priced as aggressively as ~\$30/MWh. Though impressive in pace and scale, these falling PPA prices have been offset to some degree by declining wholesale market value within high penetration markets like California, where in 2016 a MWh of solar generation was worth just 83% of a MWh of flat, round-the-clock generation within CAISO's real-time wholesale energy market. Adding battery storage is one way to at least partially restore the value of solar, and a recent PPA in Arizona for a 100 MW PV project coupled with 30 MW of 4-hour battery storage—priced at just \$45/MWh, with storage accounting for roughly one-third of the price—suggests that PV plus battery storage is becoming more cost-effective, and could thrive in the coming years.

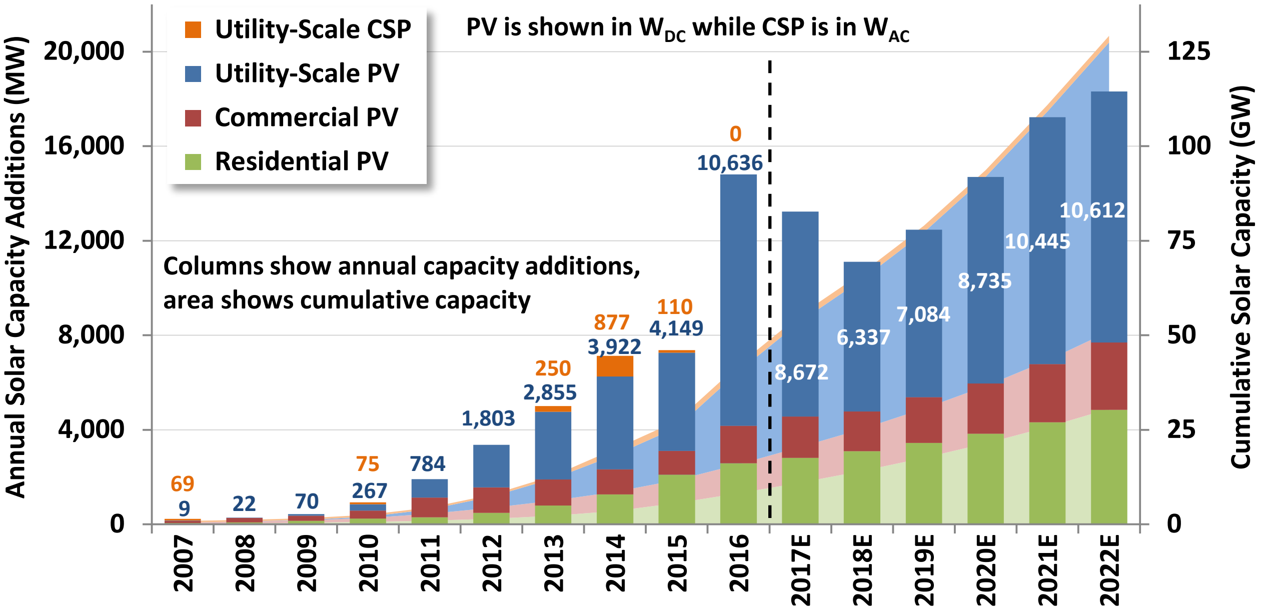
Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years. At the end of 2016, there were at least 121.4 GW of utility-scale solar power capacity within the interconnection queues across the nation, 83.3 GW of which first entered the queues in 2016 (presumably encouraged by the December 2015 ITC extension). Moreover, the growth within these queues is widely distributed across all regions of the country: California and the Southeast each account for 23% of the 83.3 GW, followed by the Northeast (17%), the Southwest (16%), the Central region (12%), Texas (6%) and the Northwest (3%). Though not all of these projects will ultimately be built, the widening geographic distribution of solar projects within these queues is as clear of a sign as any that the utility-scale market is maturing and expanding outside of its traditional high-insolation comfort zones.

Finally, this year's edition of the report includes a number of new elements worth briefly highlighting:

- For the first time, we've included capacity factor and PPA price data for projects located in Hawaii, which has been a pioneer in implementing projects that include PV plus battery storage.
- A new Figure 2 shows solar's historical contribution to overall U.S. capacity additions for the country as a whole.
- A new Table 1 shows solar penetration rates (calculated as in-state solar generation as a percentage of both total in-state generation and in-state load) for the "top ten" states in 2016.
- Section 2.2 incorporates confidential installed price data obtained from the EIA under a non-disclosure agreement for PV projects that achieved commercial operations in 2013-2015, bolstering our confidence in the quality of our data in those years.
- We've included three text boxes in the PPA price section (Section 2.5) that explore (1) the declining wholesale market value of solar in California (including curtailment data); (2) the specifications and PPA prices from the first three PV plus battery storage projects to enter our sample; and (3) the levelized cost of energy ("LCOE") of utility-scale PV, as compared to PPA prices.
- We've set up several data visualizations that are housed on the home page for this report: https://utilityscalesolar.lbl.gov. There you can also find a data workbook corresponding to the report's figures, a slide deck, and (eventually) a webinar recording.

1. Introduction

“Utility-scale solar” refers to large-scale photovoltaic (“PV”), concentrating photovoltaic (“CPV”), and concentrating solar thermal power (“CSP”) projects that typically sell solar electricity directly to utilities or other buyers, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets).[1] Although utility-scale CSP has a much longer history than utility-scale PV (or CPV),[2] and saw substantial new deployment between 2013 and 2015, the utility-scale solar market in the United States has been dominated by PV over the past decade. By the end of 2016, there was more than nine times as much utility-scale PV capacity operating in the United States as there was CSP capacity. PV’s increasing dominance follows explosive growth in recent years, culminating in a deployment spike of more than 10.6 GW_{DC} of utility-scale PV in 2016 (Figure 1).



Source: GTM/SEIA (2010-2017), LBNL’s “Tracking the Sun” and “Utility-Scale Solar” databases

Figure 1. Historical and Projected PV and CSP Capacity by Sector in the United States[3]

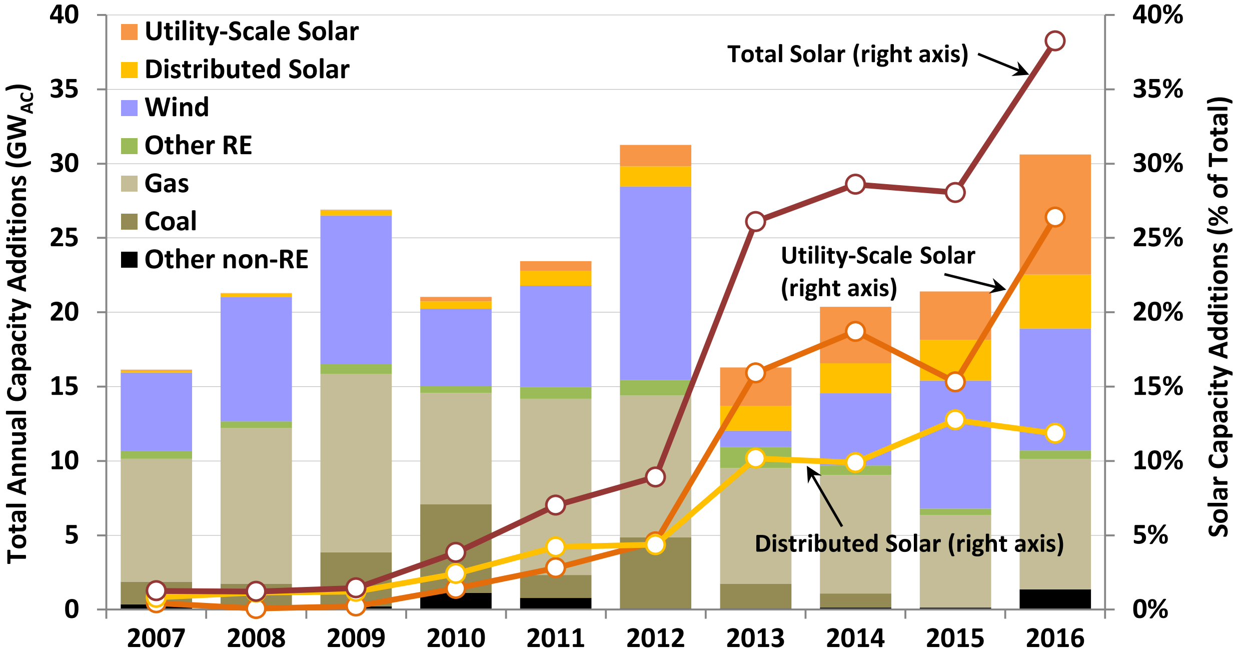
---

[1] PV and CPV projects use silicon, cadmium-telluride, or other semi-conductor materials to directly convert sunlight into electricity through the photoelectric effect (with CPV using lenses or mirrors to concentrate the sun’s energy). In contrast, CSP projects typically use either parabolic trough or, more recently, “power tower” technology to produce steam that powers a conventional steam turbine.

[2] Nine large parabolic trough projects totaling nearly 400 MW_{AC} began operating in California in the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.

[3] GTM/SEIA’s definition of “utility-scale” reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box—*Defining “Utility-Scale”*—in this chapter for a discussion of different definitions of “utility-scale”). In addition, the PV capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box—*AC vs. DC*—at the start of Chapter 2 discusses why AC capacity ratings make more sense for utility-scale PV projects). Despite these inconsistencies, the data are nevertheless useful for the purpose of providing a general sense for the size of the utility-scale market and demonstrating relative trends between different market segments and technologies.

Led by the utility-scale sector, solar power has comprised a sizable share—more than 25%—of all generating capacity additions in the United States in each of the past four years. In 2016, it constituted 38% of all U.S. capacity additions (with utility-scale solar accounting for 26%) and was the largest source of new capacity, ahead of both natural gas and wind (Figure 2).[4]



Source: ABB, AWEA, GTM/SEIA, Berkeley Lab

Figure 2. Relative Contribution of Generation Types to Annual Capacity Additions

Utility-scale PV's strong showing in 2016 was due, in part, to what had been, up until late-December 2015, a scheduled end-of-2016 reversion of the 30% federal investment tax credit ("ITC") to 10%. The December 2015 extension of the 30% ITC through 2019 brought several other changes as well. For non-residential projects (including utility-scale), the prior requirement that a project be "placed in service" (i.e., operational) by the reversion deadline was relaxed to enable projects that merely "start construction" by the deadline to also qualify. Moreover, rather than reverting from 30% directly to 10% in 2020, the credit will instead gradually phase down to 10% over several years: to 26% in 2020, 22% in 2021, and finally 10% for projects that start construction in 2022 or thereafter.[5]

Despite a substantial amount of new capacity having been "pulled forward" into 2016 in order to capture the credit before its originally scheduled expiration, with the long-term extension of the ITC in place, the utility-scale PV market is expected to remain strong at least through the early 2020s. This unprecedented and ongoing boom in the utility-scale market makes it increasingly difficult—yet, at the same time, more important than ever—to stay abreast of the latest developments and trends.

---

[4] Data presented in Figure 2 are based on gross capacity additions, not considering retirements. Furthermore, they include only the 50 U.S. states, not U.S. territories, and rely on GTM/SEIA's definition of utility-scale solar (as described in the text box on page 4).

[5] In addition, any project that qualified for a higher-than-10% ITC by starting construction prior to 2022 must also be placed in service by the end of 2023 in order to retain that higher credit; otherwise the credit drops to 10%.

This report—the fifth edition in an ongoing annual series—is designed to help identify and track important trends in the market by compiling and analyzing the latest empirical data from the rapidly growing fleet of utility-scale solar projects in the United States. As in past years, this fifth edition maintains our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box on the next page describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). As in the previous edition, we break out coverage of PV and CSP into separate chapters (Chapters 2 and 3, respectively), to simplify reporting and enable readers who are more interested in just one of these technologies to more-quickly access what they need.[6] Within each of these two chapters, we first present installation and technology-related trends (e.g., module and mounting preferences, inverter loading ratios, troughs vs. towers, etc.) among the existing fleet, before turning to empirical data on installed project prices (in $/W terms), operation and maintenance ("O&M") costs, project performance (as measured by capacity factor), and power purchase agreement ("PPA") prices (the text box on this page—*A Note on the Data Used in this Report*—provides information about the sources of these data). Chapter 4 then concludes with a brief look ahead.

A Note on the Data Used in this Report

The data sources mined for this report are diverse, and vary depending on the type of data being analyzed, but in general include the Federal Energy Regulatory Commission ("FERC"), the U.S. Energy Information Administration ("EIA"), state and federal incentive programs, state and federal regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. In most cases, the data are drawn from a sample, rather than the full universe, of solar power projects installed in the United States. Sample size varies depending on the technology (PV vs. CSP) and the type of data being analyzed, and not all projects have sufficiently complete data to be included in all data sets. Furthermore, the data vary in quality, both across and within data sources. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market data, with an emphasis on 2016; with some limited exceptions (including Figure 1 and Chapter 4), the report does not discuss forecasts or seek to project future trends.

Finally, we note that this report complements several other related studies and ongoing research activities at LBNL and elsewhere. Most notably, LBNL's annual *Tracking the Sun* report series analyzes the latest trends in residential and commercial PV project pricing, while NREL's PV system cost benchmarks are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (the text box on page 20 provides more information on NREL's utility-scale cost benchmarks). All of this work is funded by the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce utility-scale solar's levelized cost of electricity ("LCOE") to $30/MWh (in 2016 dollars) by 2030. Most of LBNL's solar-related work can be found at emp.lbl.gov/projects/solar, while information on the SunShot Initiative can be found at energy.gov/eere/sunshot/sunshot-initiative.

---

[6] Select data pertaining to the few CPV projects in our sample continue to be presented, where warranted, along with the corresponding data for PV projects in Chapter 2.

Defining “Utility-Scale”

Determining which electric power projects qualify as “utility-scale” (as opposed to commercial- or residential-scale) can be a challenge, particularly as utilities begin to focus more on distributed generation. For solar PV projects, this challenge is exacerbated by the relative homogeneity of the underlying technology. For example, unlike with wind power, where there is a clear difference between utility-scale and residential wind turbine technology, with solar, very similar PV modules to those used in a 5 kW residential rooftop system might also be deployed in a 100 MW ground-mounted utility-scale project. The question of where to draw the line is, therefore, rather subjective. Though not exhaustive, below are three different—and perhaps equally valid—perspectives on what is considered to be “utility-scale”:

- Through its Form EIA-860, the Energy Information Administration (“EIA”) collects and reports data on all generating plants of at least 1 MW of capacity, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA (“GTM/SEIA”) define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a “utility-scale” project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff (“FiT”) or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be “utility-scale” (Sternthal 2013). For PV, such financiers might consider a 25 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC} (separately, ground-mounted PV projects of 5 MW_{AC} or less, along with roof-mounted systems of all sizes, are analyzed in LBNL’s annual “Tracking the Sun” report series).

This definition is grounded in consideration of the four types of data analyzed in this report: installed prices, O&M costs, capacity factors, and PPA prices. For example, setting the threshold at 5 MW_{AC} helps to avoid smaller projects that are arguably more commercial in nature, and that may make use of net metering and/or sell electricity through FiTs or other avoided cost contracts (any of which could skew the sample of PPA prices reported later). A 5 MW_{AC} limit also helps to avoid specialized (and therefore often high-cost) applications, such as carports or projects mounted on capped landfills, which can skew the installed price sample. Meanwhile, ground-mounted systems are more likely than roof-mounted systems to be optimally oriented in order to maximize annual electricity production, thereby leading to a more homogenous sample of projects from which to analyze performance, via capacity factors. Finally, data availability is often markedly better for larger projects than for smaller projects (in this regard, even our threshold of 5 MW_{AC} might be too small).

Some variation in how utility-scale solar is defined is natural, given the differing perspectives of those establishing the definitions. Nevertheless, the lack of standardization does impose some limitations. For example, GTM/SEIA’s projections of the utility-scale market (shown in Figure 1) may be useful to readers of this report, but the definitional differences noted above (along with the fact that GTM/SEIA reports utility-scale capacity in DC rather than AC terms) make it harder to synchronize the data presented herein with their projections. Similarly, institutional investors may find some of the data in this report to be useful, but perhaps less so if they are only interested in projects larger than 20 MW_{AC}.

Until consensus emerges as to what makes a solar project “utility-scale,” a simple best practice is to be clear about how one has defined it (and why), and to highlight any important distinctions from other commonly used definitions—hence this text box.

2. Utility-Scale Photovoltaics (PV)

At the end of 2016, 427 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects totaling 16,439 MW_{AC} were fully online in the United States.[7] Nearly 45% of this capacity—i.e., 146 projects totaling 7,385 MW_{AC}—achieved commercial operation in 2016. The next five sections of this chapter analyze large samples of this population, focusing on installation and technology trends, installed prices, operation and maintenance costs, capacity factors, and finally, PPA prices. Sample size varies by section, and not all projects have sufficiently complete data to be included in all five samples and sections.

For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms throughout this report, unless otherwise noted. In addition, all data involving currency are reported in constant or real U.S. dollars—in this edition, 2016 dollars.[8]

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current (“DC”) terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current (“AC”) capacity rating—measured by the combined AC rating of the project’s inverters—is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar thermal power, or CSP) to which utility-scale PV is compared are described in AC terms—with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.

2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (described in more detail in later sections of this chapter, and portrayed in Figure 7). This increase in the “inverter loading ratio” boosts revenue (per unit of AC capacity) and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project’s DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project’s output will ultimately be constrained by the inverters’ AC rating, the project’s AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project’s AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($\$/W_{AC}$), operating costs ($\$/kW_{AC}$-year), and AC capacity factor.

---

[7] Because of differences in how “utility-scale” is defined (e.g., see the text box at the end of Chapter 1), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM Research and SEIA (2017)) of the amount of utility-scale PV capacity online at the end of 2016. For instance, Figure 5 shows that a lower amount of utility-scale PV capacity was installed in 2015 than in 2014, which stands in contrast to GTM Research and SEIA, but is the result of these definitional differences (in addition to our policy of including in each calendar year only those PV projects that have become fully operational).

[8] Conversions between nominal and real dollars use the implicit gross domestic product (“GDP”) deflator. Historical conversions use the actual GDP deflator data series from the U.S. Bureau of Economic Analysis, while future conversions (e.g., for PPA prices) use the EIA’s projection of the GDP deflator in *Annual Energy Outlook 2017* (Energy Information Administration (EIA) 2017).

2.1 Installation and Technology Trends Among the PV Project Population (427 projects, 16,439 MW_{AC})

Before progressing to analysis of project-level data on installed prices, operating costs, capacity factors, and PPA prices, this section analyzes trends in utility-scale PV project installations and technology configurations among the *entire population* of PV projects from which later data samples are drawn. The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or PPA price data presented and discussed in later sections.

States with utility-scale PV projects now outnumber those without

Figure 3 overlays the location of every utility-scale PV project in the LBNL population (including four CPV projects) on a map of solar resource strength in the United States, as measured by global horizontal irradiance ("GHI").[9] Figure 3 also defines the regions that are used for regional analysis throughout this report. Individual project markers indicate mounting and module type, delineating between projects with arrays mounted at a fixed tilt versus on tracking devices that follow the position of the sun,[10] and between projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium-telluride, or "CdTe") modules. Figure 4, meanwhile, provides a sense for how regional deployment of utility-scale solar has evolved over time.

As shown in Figure 3, most of the projects (and capacity) are located in California and the Southwest, where the solar resource is the strongest (and where state-level policies such as renewable portfolio standards, and in some cases state-level tax credits, have encouraged utility-scale solar development). Figure 4 shows that through 2014, all other regions regularly accounted for just a small amount of total new (and cumulative) capacity. But starting in 2015 and then again in 2016, these other regions besides California and the Southwest burst onto the scene, contributing ~30% of all new capacity in each year (up from ~10% in 2013 and 2014). Conversely, California's share of the market dropped from 69% and 76% in 2013 and 2014 to 47% and 40% in 2015 and 2016, respectively.[11]

---

[9] Global Horizontal Irradiance (GHI) is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance (DNI) and diffuse horizontal irradiance (DIF). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).

[10] All but eight of the 263 PV projects in the population that use tracking systems use horizontal single-axis trackers (which track the sun from east to west each day). In contrast, five recently built PV projects in Texas by OCI Solar, along with three CPV projects (and two CSP power tower projects described later in Chapter 3), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental capital and O&M costs (plus risk of malfunction), depending on the PPA price.

[11] Despite its declining market share, no state has ever added more utility-scale PV capacity in a single year than California did in 2016, with nearly 3 GW_{AC} spread among nearly 50 new utility-scale PV projects.

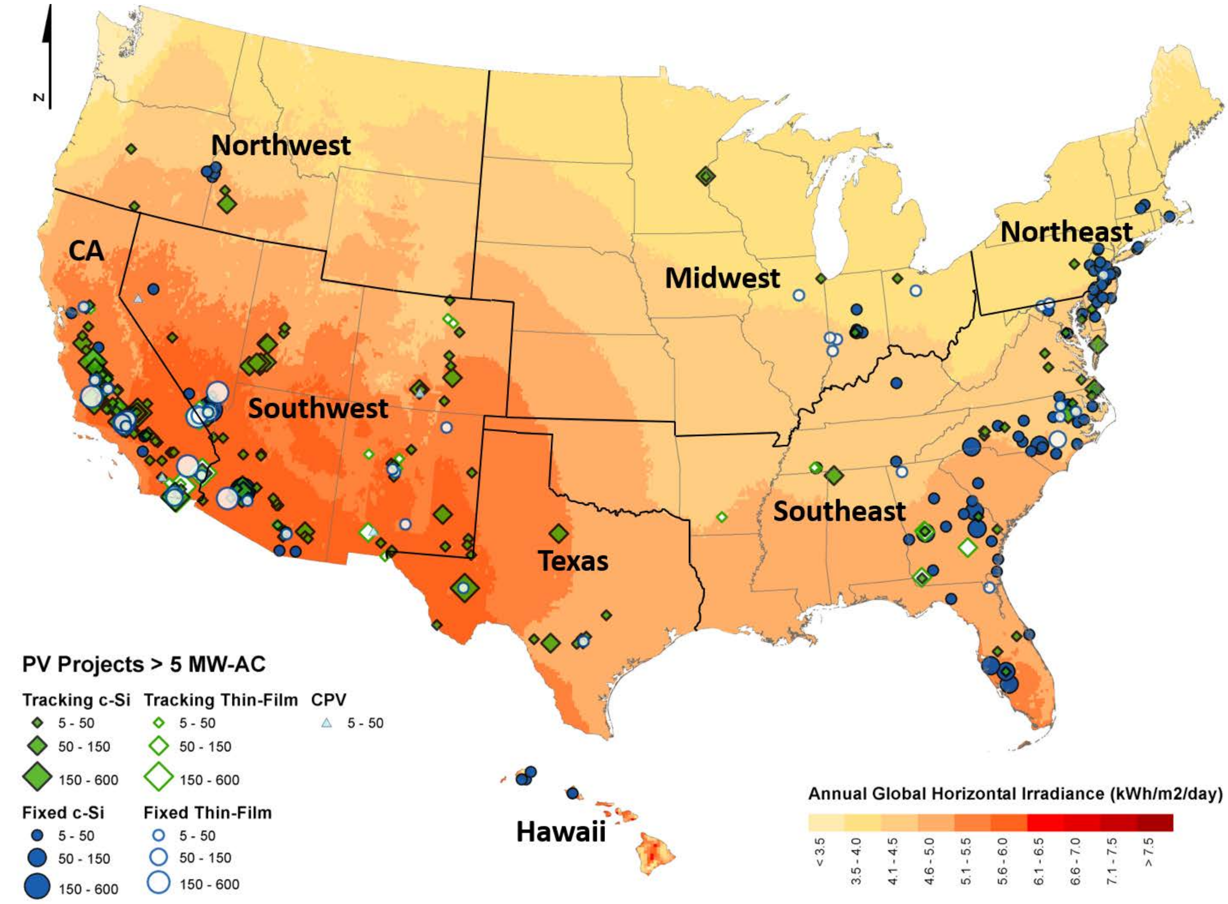

N
Northwest
CA
Southwest
Midwest
Northeast
Southeast
Texas
Hawaii
PV Projects > 5 MW-AC
Tracking c-Si
5 - 50
50 - 150
150 - 600
Tracking Thin-Film
5 - 50
50 - 150
150 - 600
CPV
5 - 50
Fixed c-Si
5 - 50
50 - 150
150 - 600
Fixed Thin-Film
5 - 50
50 - 150
150 - 600
Annual Global Horizontal Irradiance (kWh/m2/day)
< 3.5
3.5 - 4.0
4.1 - 4.5
4.6 - 5.0
5.1 - 5.5
5.6 - 6.0
6.1 - 6.5
6.6 - 7.0
7.1 - 7.5
> 7.5

Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale PV Projects

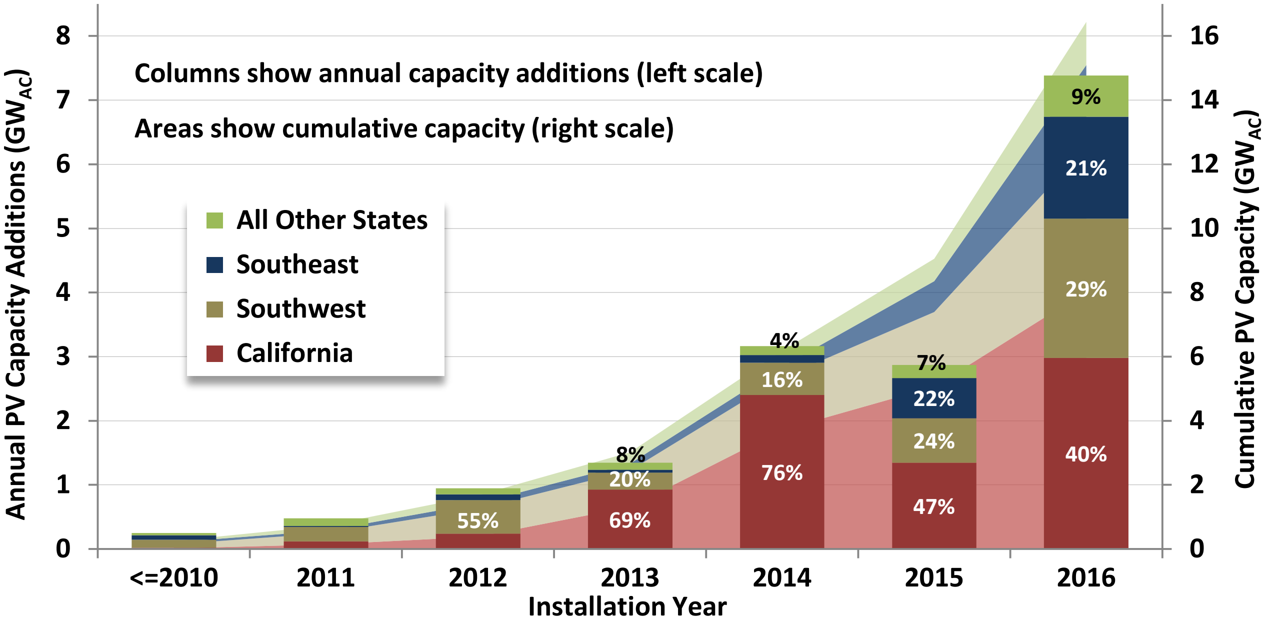


Figure 4. Annual and Cumulative Utility-Scale PV Capacity by U.S. Region

With the Northwest region's first utility-scale PV projects coming online in 2016, utility-scale solar is now present in all seven regions in the mainland United States and Hawaii. Seven new states—the most new entrants ever in a single year—added their first utility-scale PV projects in 2016,[12] bringing the total to 29 states—i.e., more than half of all states—that are now home to utility-scale solar projects larger than 5 MW_{AC}.

Table 1. U.S. Solar Power Rankings in 2016: the Top 10 States

State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	12.6%	8.3%	9.8%	6.5%
Hawaii	8.5%	1.0%	8.7%	1.0%
Vermont	8.2%	4.0%	2.8%	1.4%
Nevada	6.8%	5.8%	7.4%	6.4%
Massachusetts	6.0%	2.2%	3.7%	1.4%
Arizona	4.4%	2.9%	6.1%	4.0%
New Jersey	3.5%	1.3%	3.7%	1.4%
North Carolina	3.1%	2.9%	3.0%	2.9%
New Mexico	3.0%	2.4%	4.2%	3.5%
Utah	2.7%	2.3%	3.4%	2.9%
Rest of U.S.	*0.3%*	*0.1%*	*0.3%*	*0.1%*
TOTAL U.S.	**1.3%**	**0.8%**	**1.4%**	**0.9%**

Source: EIA's Electric Power Monthly (February 2017)

With recent growth, some states have realized or are approaching 10% solar energy penetration. Table 1 lists the top 10 states based on actual solar generation in 2016—for all market segments as well as just utility-scale[13]—divided by total in-state electricity generation (left half of table) and in-state load (right half). When considering the entire solar market (i.e., both distributed and utility-scale), California and Hawaii top the list regardless of whether penetration is based on total generation or total load, while other states—most notably Vermont—move up or down the list depending on how penetration is calculated. In 2016, five states achieved solar penetration levels of 6% or higher when total solar penetration is based on generation (four states topped 6% when penetration is based on load), while solar penetration across the entire United States stood at 1.3-1.4%.[14] Penetration rates for just utility-scale are, of course, lower than for the market as a whole, with California and Nevada leading the pack.

---

[12] Oregon energized its first seven projects in 2016 (a total of 63 MW_{AC}) while two large projects (totaling 120 MW_{AC}) came online in neighboring Idaho. Minnesota (107 MW_{AC}) entered our map with the aptly named North Star Solar Project (for now, the northern-most utility-scale PV project in our database) and the first tranche of the Aurora project portfolio. Representative of the strong growth in the Southeast, Virginia (137 MW_{AC}), Alabama (75 MW_{AC}), Kentucky (10 MW_{AC}), and South Carolina (7 MW_{AC}) all brought their first utility-scale solar projects online in 2016.

[13] The distinction between utility-scale solar and the rest of the market in Table 1 is based on the EIA's 1 MW_{AC} capacity threshold, which differs from the 5 MW_{AC} threshold adopted in this report.

Tracking c-Si projects dominate 2016 additions

Figure 5 shows the same data as Figure 4, but broken out by technology configuration (mounting and module type) rather than location. The percentage of newly built projects using tracking increased from 63% in 2015 to 71% in 2016 (in capacity terms, from 70% in 2015 to 79% in 2016). Although tracking has been the dominant mounting choice for c-Si projects for roughly six years now (as tracking costs have come down, reliability has improved, and the 30% ITC has helped defray the incremental up-front cost), the pairing of tracking with thin-film modules is a more-recent phenomenon, driven in large part by significant improvements in the efficiency of CdTe modules in recent years.[15] As was the case for the first time in 2014, more new thin-film projects used tracking (15 projects) than fixed-tilt mounts (6 projects) in 2016 as well. Furthermore, as in 2015, the *capacity* of new thin-film projects using tracking (1,107 MW_{AC}) again surpassed that of fixed-tilt thin-film projects (620 MW_{AC}) by a wide margin in 2016.

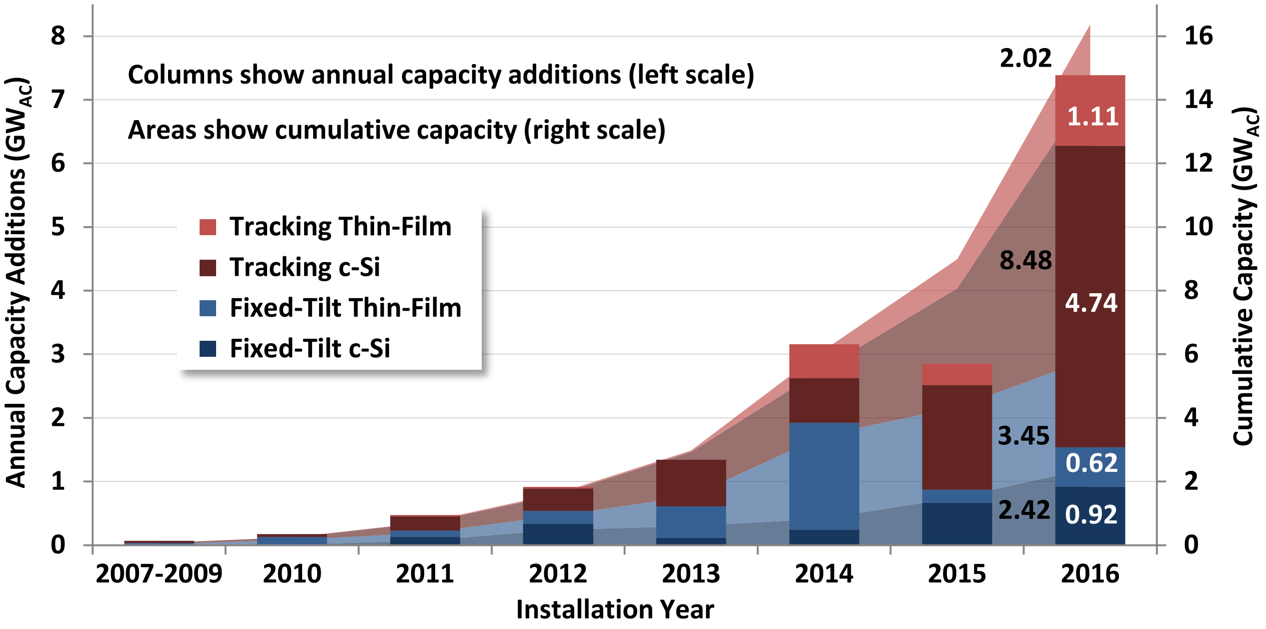


Figure 5. Annual and Cumulative Utility-Scale PV Capacity by Module and Mounting Type

---

[14] These 2016 penetration numbers do not fully capture the generation contribution of the large amount of new solar power capacity added during 2016, particularly if added towards the end of the year.

[15] Prior to 2014, only two thin-film tracking projects had ever been built in the United States, in stark contrast to more than one hundred c-Si tracking projects. Tracking has not been as common among thin-film projects historically, largely because the lower efficiency of thin-film relative to c-Si modules in the past required more land area per nameplate MW—a disadvantage exacerbated by the use of trackers. In recent years, however, leading thin-film manufacturer First Solar has increased the efficiency of its CdTe modules at a faster pace than its multi-crystalline silicon competitors, such that at the end of 2016, First Solar's CdTe module efficiency stood at 16.6%, roughly on par with multi-crystalline at ~16%-17% (though both still lag *mono*-crystalline modules by several percentage points—e.g., SunPower's E20 series at 20.5% or the mono PERC modules of Trina, Jinko and Canadian Solar at ~18.5%).

As was also the case in 2015, c-Si modules were the dominant choice for utility-scale solar additions in 2016, with 5.66 GW_{AC} of new capacity broadly distributed between Trina Solar (22% market share), Jinko Solar (14%), Canadian Solar (14%), SunPower (8%), and a number of other manufacturers having a market share of less than 5% each. In contrast, First Solar, which manufactures CdTe modules, accounts for nearly all (97%) of the 1.73 GW_{AC} of new thin-film capacity added to the project population in 2016, with the remainder (45 MW_{AC}) coming from Solar Frontier, a Japanese manufacturer of "CIGS" (copper indium gallium selenide) modules.

Figure 5 also breaks down the composition of *cumulative* installed capacity as of the end of 2016. Tracking projects (of any module type) account for 64% of the cumulative installed utility-scale PV capacity through 2016, while c-Si modules are used in 67% of cumulative capacity. Breaking these cumulative capacity statistics out by both module *and* mounting type, the most common combination was tracking c-Si (8,479 MW_{AC} from 219 projects), followed by fixed-tilt thin-film (3,448 MW_{AC} from 46 projects), fixed-tilt c-Si (2,423 MW_{AC} from 117 projects), and finally tracking thin-film (2,024 MW_{AC} from 40 projects).

More PV projects at lower insolation sites, fixed-tilt mount less common in sunny areas

Figures 3 and 4 (earlier) provide a general sense for *where* and in what type of solar resource regime utility-scale solar projects within the population are located (Figure 3), as well as *when* these projects achieved commercial operation (Figure 4). Figure 6 further refines the picture by showing the median site-specific long-term average annual GHI (in $kWh/m^2/day$) among new utility-scale PV projects built in a given year. Knowing how the average resource quality of the project fleet has evolved over time is useful, for example, to help explain observed trends in project-level capacity factors by project vintage (explored later in Section 2.4).

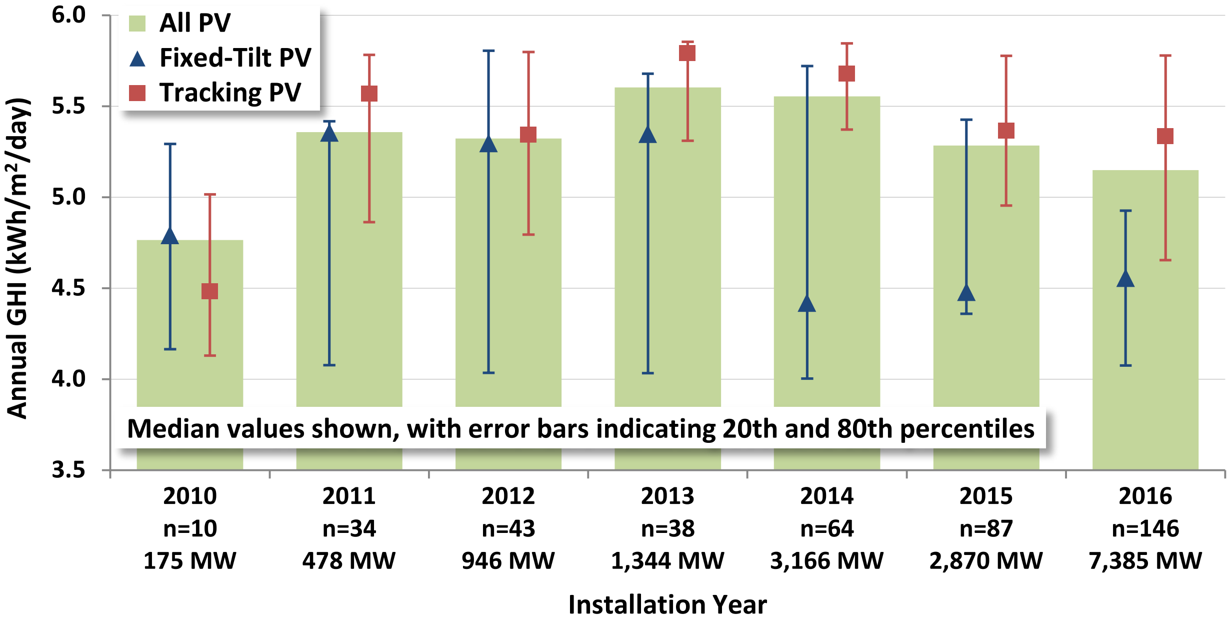


Figure 6. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

Until 2013, the median GHI among all utility-scale PV projects (shown by the green columns) had generally increased with project vintage, suggesting an ongoing concentration of projects located in solar-rich California and the Southwest. Since then, however, large-scale PV projects have been increasingly deployed in less-sunny areas as well, resulting in a decline in the median solar resource among new projects, from a high of 5.60 kWh/m^2/day among 2013-vintage projects to 5.15 kWh/m^2/day among projects built in 2016.

Moreover, the map in Figure 3 shows a preponderance of tracking projects in California and the Southwest, compared to primarily fixed-tilt c-Si projects in the lower-irradiance East. This split can also be seen in Figure 6 via the notable differences between the 20th percentile GHI numbers for fixed-tilt and tracking projects, with the former commonly as low as 4 kWh/m^2/day across most vintages, compared to much higher levels for tracking projects. The wide range of insolation among fixed-tilt projects reflects the fact that most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects (often using CdTe thin-film technology[16]) have historically also been built in high-GHI areas like California and the Southwest. Although there were still a few of these large legacy projects that came online in 2016 in the Southwest, the majority of fixed-tilt installations are now relegated to less-sunny regions. One exception to this general rule of thumb involves several 2016 fixed-tilt installations in Florida, Georgia and South Carolina.

In contrast, tracking projects have historically been concentrated in California and the Southwest, but single-axis tracking technology has increasingly been deployed in less-sunny regions as well, particularly since 2014. Notably, the northern-most PV projects that came online in Minnesota in 2016 have elected to use tracking, reflecting decreasing price differences between fixed-tilt and tracking projects that are further explored in Section 2.3.

To complement and facilitate the interpretation of the solar resource numbers in Figure 6, Table 2 provides the median GHI and 20th-80th percentile range by region among our project sample.

Table 2. Typical GHI Range of PV Projects by Region

Region	Installed Projects (#)	Cumulative Capacity (MW$_{AC}$)	Median GHI Resource (kWh/m^2/day)	20th-80th Percentiles (GHI)
Southwest	107	4,504	5.6	5.3 – 5.8
California	157	8,040	5.6	5.3 – 5.8
Hawaii	4	36	4.9	4.6 – 5.4
Texas	14	569	4.8	4.8 – 5.6
Northwest	9	183	4.6	4.5 – 4.7
Southeast	86	2,549	4.5	4.4 – 4.7
Midwest	18	244	4.0	3.9 – 4.0
Northeast	32	313	4.0	3.9 – 4.0

---

[16] The apparent preference for thin-film (primarily CdTe) modules in Desert Southwest projects is driven primarily by CdTe's greater tolerance for high-temperature environments (as well as relatively low land prices in the desert, which helped to mitigate CdTe's historical efficiency deficit). In its online blog (First Solar 2016), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at high/normal operating temperatures, due to its lower power temperature coefficient of -0.28%/°C for Series 4 modules (compared to something more like -0.40%/°C for most c-Si modules).

Developers continued to favor larger module arrays relative to inverter capacity

Another project-level characteristic that can influence both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[17] With the cost of PV modules having dropped precipitously (more rapidly than the cost of inverters), many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which—like tracking—boosts the capacity factor,[18] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production periods).[19] The resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to the sunniest months).

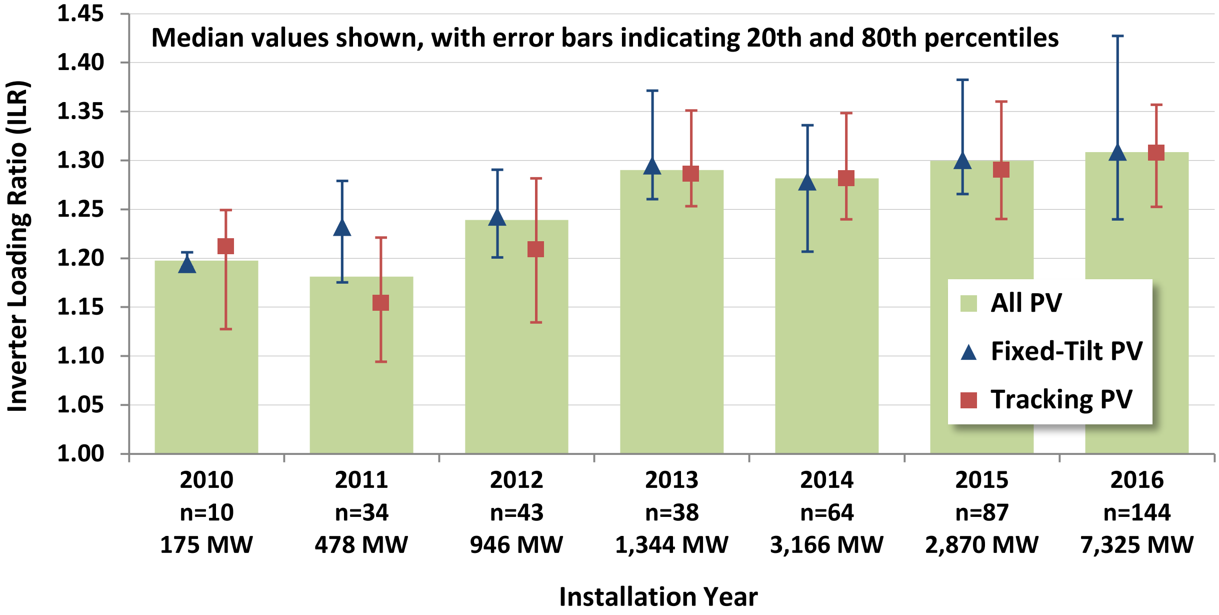


Figure 7. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

---

[17] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). This report uses inverter loading ratio, or ILR.

[18] This is analogous to the boost in capacity factor achieved by a wind turbine when the size of the rotor increases relative to the turbine's nameplate capacity rating. This decline in "specific power" (W/m^2 of rotor swept area) causes the generator to operate closer to (or at) its peak rating more often, thereby increasing capacity factor.

[19] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even "sees" the excess DC power—rather, it is simply not generated in the first place. Only *potential* generation is lost.

Figure 7 shows the median ILR among projects built in each year, both for the total PV project population (green columns) and broken out by fixed-tilt versus tracking projects. Across all projects, the median ILR has increased over time, from around 1.2 in 2010 to 1.31 in 2016. Fixed-tilt projects have historically featured higher ILRs than tracking projects, consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, “tracking-like” daily production profile. Since 2013, however, the median ILR of tracking and fixed-tilt projects has been nearly the same (although the 80th percentile has been higher for fixed-tilt than tracking projects in 2013, 2015, and most notably 2016).

2.2 Installed Project Prices (361 projects, 14,469 MW_{AC})

This section analyzes installed price data from a large sample of the overall utility-scale PV project population described in the previous section.[20] It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by mounting type (fixed-tilt vs. tracking), system size, and region. A text box at the end of this section compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

Sources of installed price information include the Energy Information Administration (EIA),[21] the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, and finally, the trade press. All prices are reported in real 2016 dollars.

In general, only fully operational projects for which all individual phases were in operation at the end of 2016 are included in the sample[22]—i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2017 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent fluctuations in component costs or other changes in market conditions. For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV, and may differ from the average installed prices reported elsewhere (Fu, Feldman, and Margolis 2017; GTM Research and SEIA 2017). That said, the text box at the end of this section suggests fairly good agreement between our empirical installed price data and other published modeling estimates, once timing is taken into account.

Our sample of 361 PV (and CPV) projects totaling 14,469 MW_{AC} for which installed price estimates are available represents 85% of the total number of PV projects and 88% of the amount of capacity in the overall PV project population described in Section 2.1. Focusing just on those PV projects that achieved commercial operation in 2016, our sample of 88 projects totaling 5,497 MW_{AC} represents 60% and 74% of the total number of 2016 projects and capacity in the population, respectively.

---

[20] Installed "price" is reported (as opposed to installed "cost") because in many cases, the value reported reflects either the price at which a newly completed project was sold (e.g., through a financing transaction), or alternatively the fair market value of a given project—i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.

[21] New to the 2016 edition of this report is the inclusion of confidential project-level installed cost data for projects built in 2013-2015, obtained from the EIA under a non-disclosure agreement.

[22] In contrast, later sections of this chapter do present data for individual phases of projects that are online, or (in the case of Section 2.5 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

Median prices fell to $2.2/W$_{AC}$ ($1.7/W$_{DC}$) in 2016

Figure 8 shows installed price trends for PV projects completed from 2007 through 2016 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is often reported in $/W$_{DC}$ terms as well (Barbose and Darghouth 2017; GTM Research and SEIA 2017). As noted in the earlier text box (*AC vs. DC*), however, this report analyzes utility-scale solar in AC terms. Figure 8 shows installed prices in both $/W$_{DC}$ and $/W$_{AC}$ terms in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this document, however, reports sample statistics exclusively in AC terms, unless otherwise noted.

As shown, median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $2.2/W$_{AC}$ ($1.7/W$_{DC}$) in 2016. This represents a price decline of more than 65% since the 2007-2009 period (and nearly 60% since 2010). The lowest-priced projects in our 2016 sample of 88 PV projects were ~$1.5/W$_{AC}$ (~$1.1/W$_{DC}$), with the lowest 20th percentile of projects falling from $2.2/W$_{AC}$ in 2015 to $2.0/W$_{AC}$ in 2016 (i.e., from $1.6/W$_{DC}$ to $1.5/W$_{DC}$).

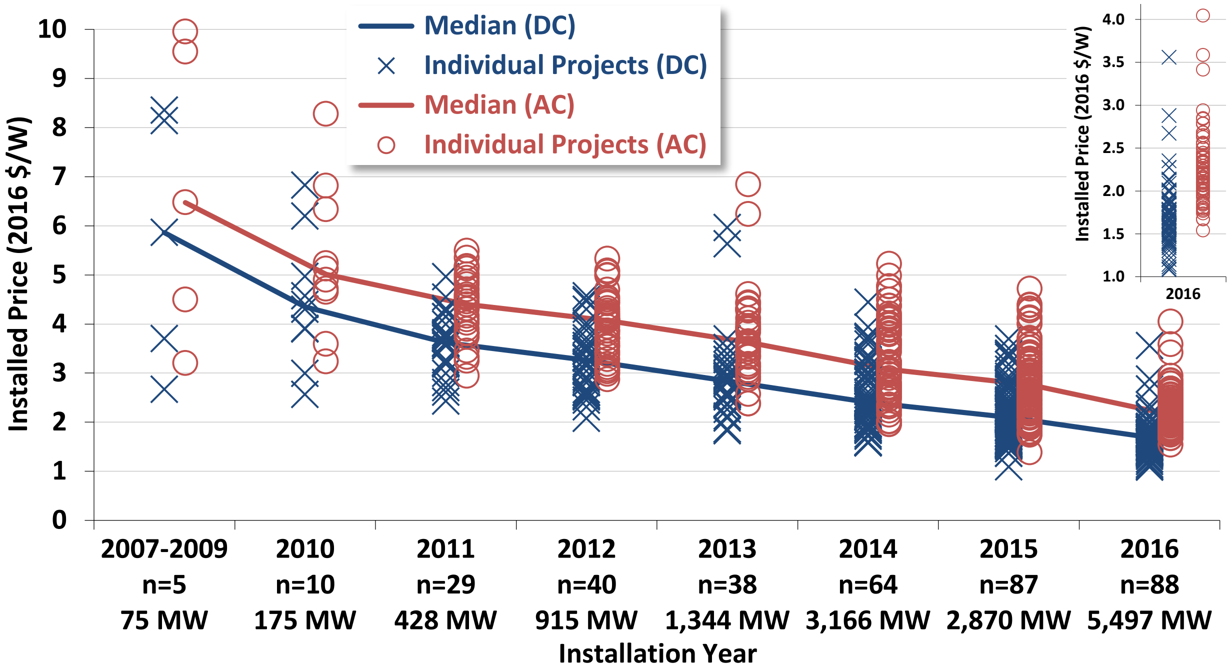


Figure 8. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

Figure 9 shows histograms drawn from the same sample, with an emphasis on the changing distribution of installed prices (which are reported only in $/W$_{AC}$ terms from here on) over the last five years. The steady decline in installed prices by project vintage is evident as the mode of the sample (i.e., the price bin with the most projects, forming the "peak" of each curve) shifts to the left from year to year. Additionally, the portion of the sample that falls into relatively high-priced bins (e.g., $2.75-$5.75/W$_{AC}$) decreases with each successive vintage, while the portion that falls into relatively low-priced bins (e.g., $1.25-$2.75/W$_{AC}$) increases. The "width" of the curves also narrows somewhat over time, indicating that the pricing within each successive vintage becomes less heterogeneous. This has become especially true for 2016 installations, the year with the lowest price dispersion and the highest concentration within the narrow price bin of \$1.75-\$2.25/W_{AC}.

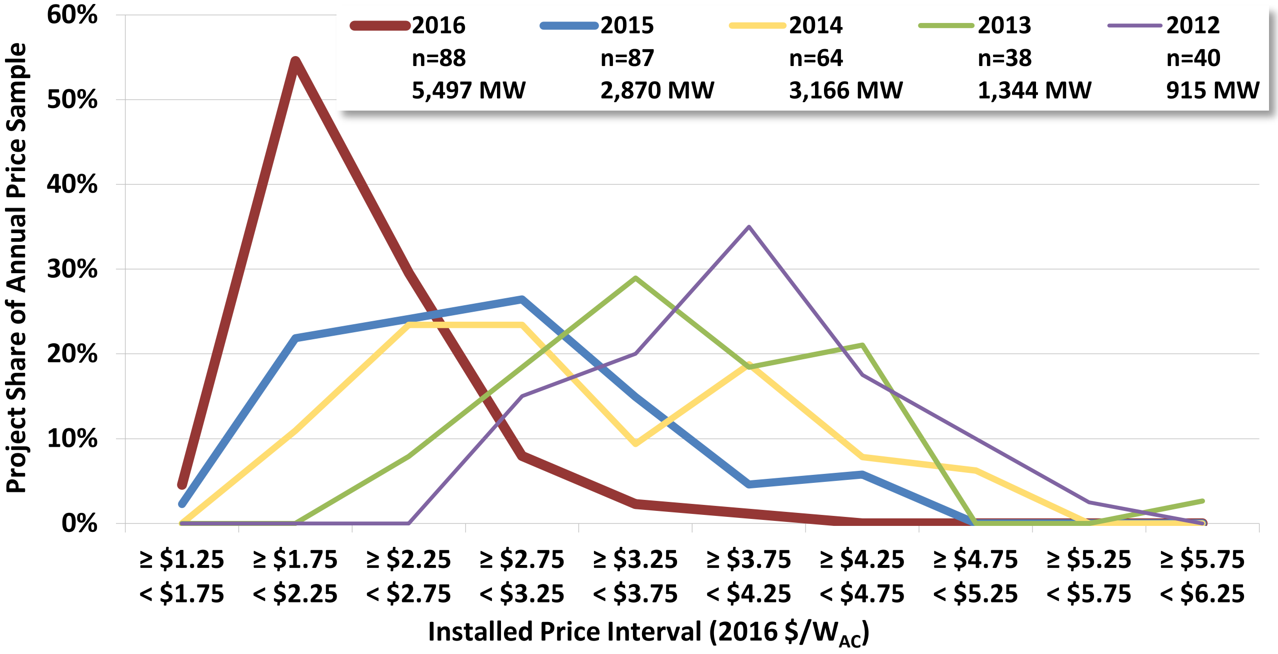


Figure 9. Distribution of Installed Prices by Installation Year

Tracking projects often command a price premium over fixed-tilt installations

While median prices in the sample have declined over time, Figure 8 shows that there has been a considerable spread in individual project prices within each year. One contributor to this price variation could be whether projects are mounted at a fixed tilt or on a tracking system. Figure 10 breaks out installed prices over time by mounting type, and finds that projects using trackers were \$0.15/W_{AC} more expensive (at the median) than fixed-tilt projects in 2016. Though once quite large (in 2010 and earlier), this tracker premium has been rather modest since 2011. As shown later in Section 2.4, this slightly higher up-front expenditure for tracking results in greater energy production (and hence revenue), which typically outweighs the added cost, helping to explain the recent surge in tracking projects, even among the most-northerly projects in our sample (e.g., in Minnesota).

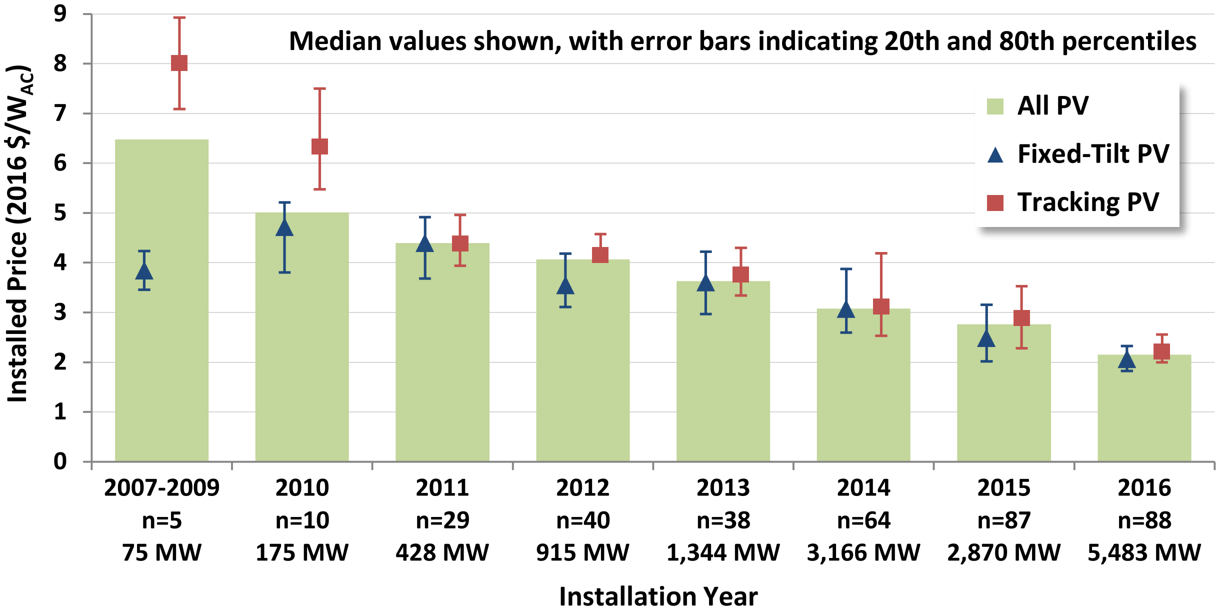


Figure 10. Installed Price of Utility-Scale PV by Mounting Type and Installation Year

Evidence of economies of scale remains elusive

Differences in project size may also explain some of the variation in installed prices seen in Figure 8, as PV projects in the sample range from 5.5 MW_{AC} to 300 MW_{AC}. Figure 11 investigates price trends by project size, focusing on just those PV projects in the sample that became fully operational in 2016, in order to minimize the potentially confounding influence of price reductions over time.

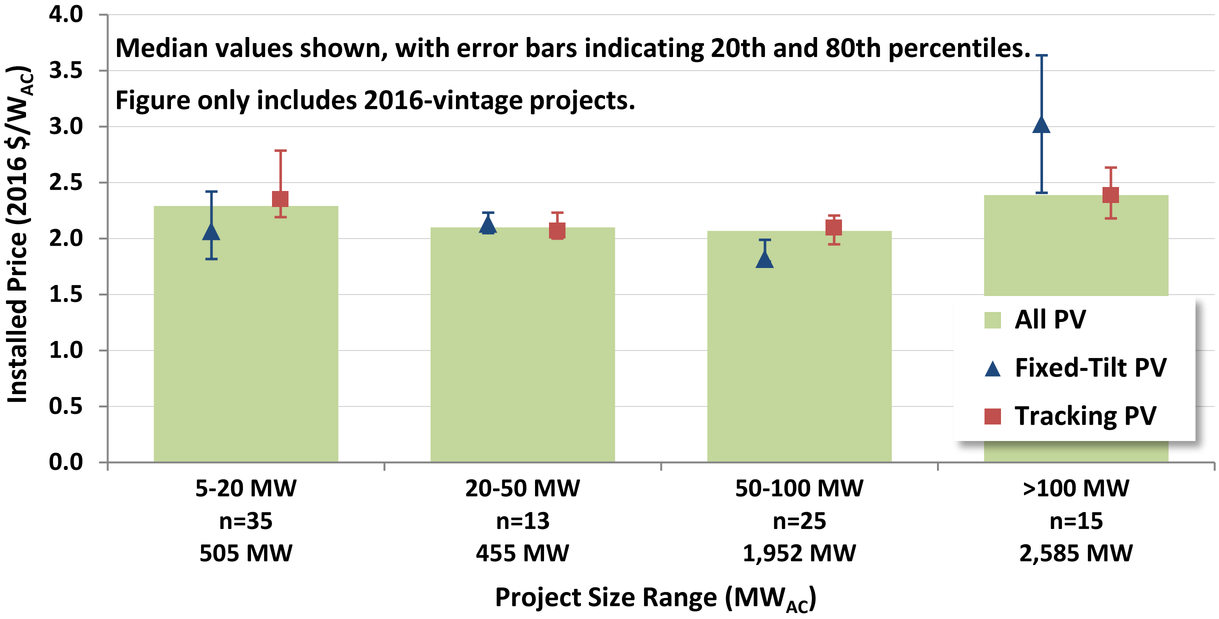


Figure 11. Installed Price of 2016 PV Projects by Size and Mounting Type

As has been the case in previous editions of this report, it is difficult to find clear indications of economies of scale among our latest project sample. That said, this year there are at least some suggestions of scale economies among the first three project size bins shown in Figure 11, with median prices dropping from \$2.29/W_{AC} (5-20 MW_{AC}) to \$2.10/W_{AC} (20-50 MW_{AC}) to \$2.07/W_{AC} (50-100 MW_{AC}).

Moving beyond those first three bins, however, the median installed price then *rises* to \$2.4/W_{AC} among the 15 projects that exceed 100 MW_{AC}. In other words, just like in last year's edition of this report (among the sample of 2015-vintage projects), the 2016 sample shown in Figure 11 once again suggests price *penalties* for projects larger than 100 MW_{AC} (although the price penalty is much less pronounced in 2016 in comparison to previous years).[23] Two factors may contribute to these apparent *dis*economies of scale for very large projects. First, it may be that these very large projects often face greater administrative, regulatory, and interconnection costs than do smaller projects, and these costs are not fully offset by other size-driven savings like hardware procurement or a more-streamlined use of installation labor. A second explanation may be that very large projects take longer to build, and may therefore reflect higher module and EPC costs dating back further in time.

System prices vary by region

In addition to price variations due to technology and perhaps system size, prices also differ by geographic region. This variation may, in part, reflect the relative prevalence of different system design choices (e.g., the greater prevalence of tracking projects in California and the Southwest) that have cost implications. In addition, regional differences in labor and land costs, soil conditions or snow load (both of which have structural, and therefore cost, implications), or simply the balance of supply and demand, may also play a role. As shown in Figure 12 (which uses the regional definitions shown earlier in Figure 3), the overall regional price variation declined between 2015 and 2016.

The first installations in the Northwest were comparatively slightly more expensive, perhaps explained by an absence of previously established installation infrastructure. California prices saw a strong decline and are now much closer to the national median. As in previous years, the Southwest and the Southeast have lower prices than the national median, although their price lead has shrunk from about \$0.36/W_{AC} in 2015 to \$0.05/W_{AC} in 2016. Despite its nascent state, the Midwest is the region with the lowest prices in 2016, at \$1.9/W_{AC}, although cost estimates for the Northeast, the Midwest and Northwest should be considered with caution, as the sample size for all three regions is rather small. Due to the low number of observations, projects in Hawaii and Texas are not reported in Figure 12.

---

[23] These empirical findings are, to some extent, in conflict with recent modeling work from NREL (Fu, Feldman, and Margolis 2017) that models the cost of projects in construction in Q1 2017 (that are not yet commercially operable). NREL projects a \$0.4/W_{DC} cost advantage for a 100 MW_{DC} utility-scale PV plant over a 5 MW_{DC} project. However, the analysis does not correct for the potentially longer development times associated with the larger project, which could diminish the cost advantage when prices are indexed by commercial operation date.

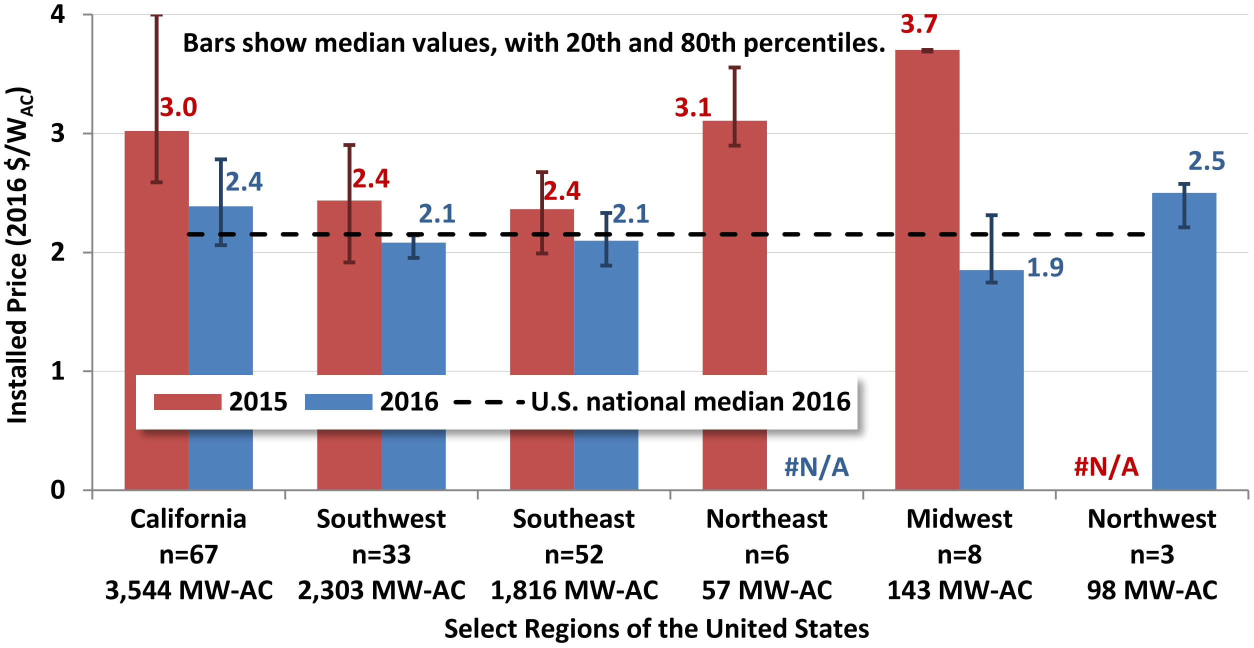


Figure 12. Median Installed PV Price by Region in 2015 and 2016

Finally, the text box on the next page compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

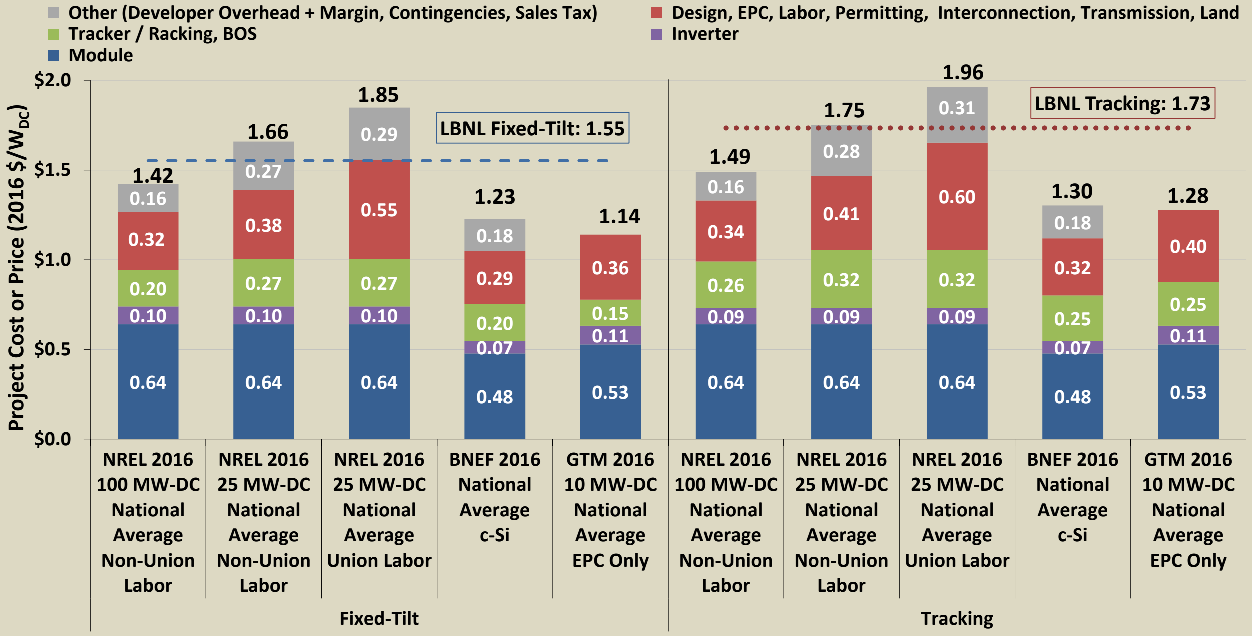
Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this report generally represent empirical *top-down* price estimates gathered from sources (e.g., corporate financial filings, FERC filings, the Treasury's Section 1603 grant database, the EIA) that typically do not provide more granular insight into component costs. In contrast, several publications by NREL (Fu, Feldman, and Margolis 2017), BNEF (Bromley and Serota 2016), and Greentech Media (GTM Research and SEIA 2017) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed cost or price. Each type of estimate has both strengths and weaknesses—e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check that captures the full range of diverse projects in the market, while bottom-up estimates provide more detail but rely on modeling, typically of idealized or "best in class" projects.

A second potential source of disparity between these installed price estimates is differences in the "time stamp." LBNL reports the installed price of projects in the year in which they achieve commercial operation, while GTM and BNEF may instead refer to EPC contract execution dates or to projects under construction that have not yet been completed (such projects enter our sample in later years). NREL also provides more of a forward-looking estimate (in the figure below, we account for this timing mismatch by showing NREL's 1Q16, rather than current, numbers).

Notwithstanding these potential timing issues, the figure below compares the top-down median 2016 prices for fixed-tilt (\$1.55/W_{DC}) and tracking (\$1.73/W_{DC}) projects in the LBNL sample with various bottom-up modeled cost estimates from the three sources noted above. Each bottom-up cost estimate is broken down into a common set of cost categories, which we defined rather broadly in order to capture slight differences in how each source reports costs (note that not all sources provided estimates for all cost categories). Finally, costs are shown exclusively in \$/W_{DC}, which is how they are reported in these other sources.

Although GTM's relatively low cost estimates stand out as potential outliers, they represent only turnkey EPC costs—i.e., they exclude permitting, interconnection, and transmission costs, as well as developer overhead, fees, and profit margins—which perhaps explains the difference. LBNL's top-down empirical estimates reflect a mix of union and non-union labor and span a wide range of project sizes and prices.[i] Finally, economies of scale of \$0.24-26/W_{DC} are reflected in NREL's bottom-up modeled cost estimates for a 100 MW_{DC} project (relative to a 25 MW_{DC} project).



---

[i] For fixed-tilt projects, LBNL's median project size is 23 MW_{DC} and the price range is \$1.08-\$3.56/W_{DC}. For tracking projects, the comparable numbers are 74 MW_{DC} and \$1.24-\$2.88/W_{DC}.

2.3 Operation and Maintenance Costs (30 projects, 546 MW_{AC})

In addition to up-front installed project prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs to operate and maintain the generating plant itself. In other words, O&M costs—at least as reported here—exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Few of the utility-scale solar projects that have been operating for more than a year are owned by regulated investor-owned utilities, which FERC requires to report (on Form 1) the O&M costs of the power plants that they own.[24] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). For example, at least historically, some investor-owned utilities have not reported empirical O&M costs for individual solar projects, but instead have reported average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 3 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Table 3. Operation and Maintenance Cost Sample (cumulative over time)

Year	PG&E		PNM[25]		Nevada Power		Georgia Power		APS[26]		PSEG[27]		FP&L	
	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects
2011									51	3			110	3
2012	50	3	8	2					96	4			110	3
2013	100	6	30	4					136	6			110	3
2014	N/A	N/A	55	7					168	7			110	3
2015	150	9	95	11					191	9			110	3
2016	150	9	95	11	16	1	36	2	237	10	44	3	110	3
predominant technology	Fixed-Tilt c-Si		4 Fixed-Tilt, 7 Tracking		Tracking c-Si		Fixed-Tilt c-Si		Tracking c-Si		Fixed-Tilt c-Si		mix of c-Si and CSP	

---

[24] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses"—namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).

[25] PNM only reports fleet-wide average O&M costs, weighing each of their projects by its MW_{AC} capacity

[26] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 237 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 10 utility-scale solar plants with a combined capacity of 221 MW_{AC}.

[27] PSEG only reports a fleet-wide average of O&M cost which may include other non-utility-scale solar projects in addition to its large landfill solar projects.

Despite these limitations, Figure 13 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (PV, blue solid line) and $/MWh (PV, red dashed line). The error bars represent both the lowest and the highest utility fleet-wide PV cost in each year. The yellow dotted line, meanwhile, shows the annual O&M costs of FP&L's 75 MW CSP plant (in $/kW-year terms only, because this project provides steam to a co-located combined cycle gas plant). Although this chapter focuses on PV projects, we have included this lone CSP plant here largely for the sake of expediency, given that it is the only CSP project for which we have O&M cost data. Not surprisingly, its O&M costs—which may not even be fully representative if they reflect just the solar collector field and not the power block of the gas-fired combined cycle plant—are well above those of the PV projects shown.

Average O&M costs for the cumulative set of PV plants within this sample have steadily declined from about $31/kW$_{AC}$-year (or $19/MWh) in 2011 to about $16/kW$_{AC}$-year ($7/MWh) in 2015, but rose in 2016 to $18/kW$_{AC}$-year ($8/MWh). And while the average O&M expense across all utilities has increased slightly in 2016, the utilities with the highest- and lowest-cost fleets have been able to lower their relative costs in both $/kW-year and $/MWh terms (see error bars). This general declining trend potentially indicates that utilities are capturing economies of scale as their PV project fleets grow over time. In 2016, all but three out of 15 PV projects in the sample (i.e., in those instances where we have project-level rather than aggregate utility data) had O&M costs of less than $20/kW$_{AC}$-year (or $11/MWh).

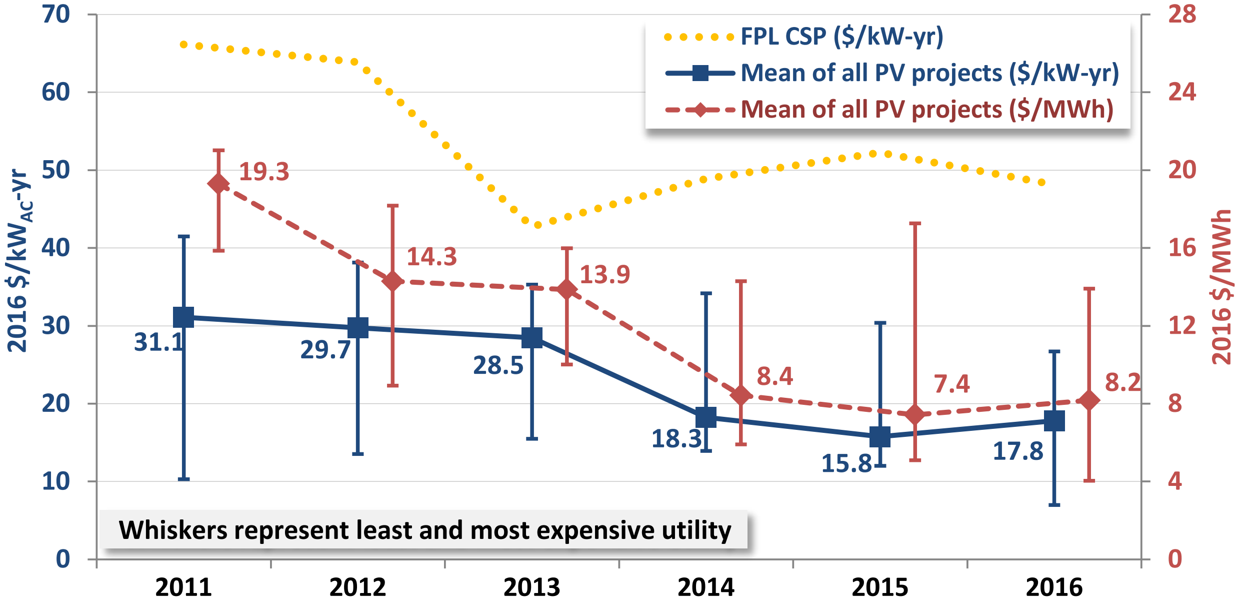


Figure 13. Empirical O&M Costs Over Time for Growing Cumulative Sample of Projects

As utility ownership of operating solar projects increases in the years ahead (and as those utilities that already own substantial solar assets but do not currently report operating cost data hopefully begin to do so, as required in FERC Form 1), the sample of projects reporting O&M costs should grow, potentially allowing for more interesting analyses in future editions of this report.

2.4 Capacity Factors (260 projects, 8,733 MW_{AC})

At the close of 2016, more than 260 utility-scale PV projects in the United States had been operating for at least one full year, and in some cases for as many as nine years, thereby enabling the calculation of capacity factors.[28] Sourcing empirical net generation data from FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings, this chapter presents net AC capacity factor data for 260 PV projects totaling 8,733 MW_{AC}. This 8.7 GW_{AC} sample represents a significant increase from the 5.9 GW_{AC} sample for which capacity factor data were analyzed in last year's edition of this report, driven in large part by new projects that began operating in 2015.

The capacity factors of individual projects in this sample range widely, from 15.4% to 35.5%, with a sample mean of 25.8%, a median of 26.3%, and a capacity-weighted average of 27.3%. Notably, these are *cumulative* capacity factors—i.e., calculated over as many years of data as are available for each individual project (up to a maximum of nine years, from 2008 to 2016, in this case), rather than for just a single year (though for projects completed in 2015, only a single full calendar year of data—2016—exists at present). Furthermore, they are also expressed in *net*, rather than *gross*, terms—i.e., they represent the output of the project net of its own consumption. Finally, they are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[29] yielding higher capacity factors than if reported in DC terms,[30] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or thermal energy sources), which are also calculated in AC terms.

Wide range in capacity factors reflects differences in insolation, tracking, and ILR

Figure 14 presents the cumulative net AC capacity factors of each project in the sample (see the circle markers) broken out by three key project characteristics that a recent statistical analysis (Bolinger, Seel, and Wu 2016) found to explain more than 90% of the variation in utility-scale PV project capacity factors. These characteristics include the estimated strength of the long-term solar resource at each site (measured in GHI with units $kWh/m^2/day$), whether the array is mounted at a fixed tilt or on a tracking mechanism, and the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR).[31] The blue-shaded columns show the mean cumulative capacity factor within each individual bin.

---

[28] Because solar generation is seasonal (greater in the summer than in the winter), capacity factor calculations are performed in full-year increments.

[29] The formula is: Net Generation (MWh_{AC}) over Single- or Multi-Year Period / [Project Capacity (MW_{AC}) * Number of Hours in that Same Single- or Multi-Year Period].

[30] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

[31] Instead of using capacity factors to gauge project performance, some analysts prefer to use the "performance ratio"— defined as "the ratio of the electricity generated to the electricity that would have been generated if the plant consistently converted sunlight to electricity at the level expected from the DC nameplate rating" (Dierauf et al. 2013). Because the performance ratio takes into account many of the variables explored in this section—e.g., fixed-tilt vs. tracking mounts, variations in insolation, DC capacity ratings, etc.—it can provide a more precise measure of how a project is performing *in light of its specific circumstances*. In this report, however, we are specifically interested in exploring the full range of empirical project performance experienced in the market, as well as the specific circumstances that drive it, and therefore prefer to focus on capacity factors, which do not filter out this

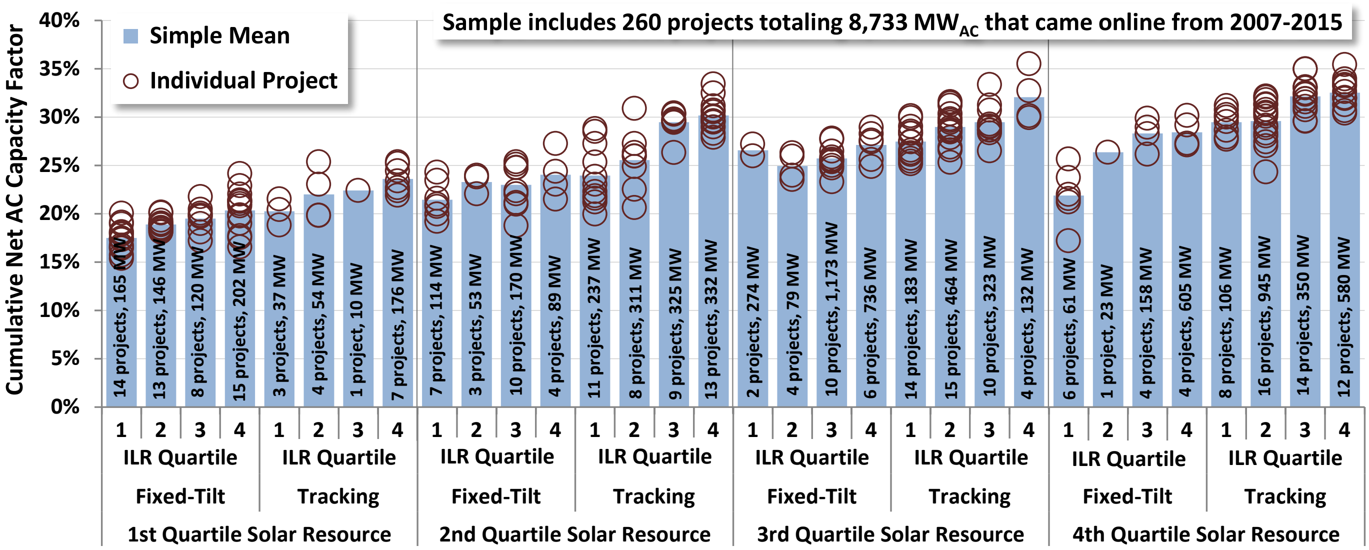


Figure 14. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio[32]

Each of the three drivers of capacity factor explored in Figure 14 is discussed in turn below.

- **Solar Resource:** Based on its geographic coordinates, each project in the sample is associated with a long-term average global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Figure 14 then parses the sample into solar resource quartiles that have the following thresholds: <4.52, 4.52-5.37, 5.37-5.74, and ≥5.74 kWh/m^2/day GHI. Sixty-five projects fall into each resource quartile, though capacity is concentrated in the third (39%) and fourth (32%) quartiles, with only 10% of capacity within the first quartile. Not surprisingly, projects sited in stronger solar resource areas tend to have higher capacity factors, all else equal. The difference can be substantial: the mean capacity factors in the highest resource bin, for example, average 8 percentage points higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending from 4 to 10 percentage points depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** 111 projects in the sample (totaling 4,168 MW$_{AC}$) are mounted at a fixed-tilt, while the remaining 149 (totaling 4,564 MW$_{AC}$) utilize tracking

---

information. In addition, some of the information required to calculate performance ratios—e.g., site-specific insolation during the period of interest—is not readily accessible, making capacity factors a more expedient choice for this report.

[32] Figure 14 (as well as the rest of this section) excludes three CPV projects: the 5.04 MW$_{AC}$ Hatch project (online since late-2011), the 30 MW$_{AC}$ Cogentrix Alamosa project (online since early 2012), and the 6.3 MW$_{AC}$ Desert Green project (online since late-2014). If plotted in Figure 14, these three projects would fall into the 29th, 14th, and 32nd bins, respectively, where their cumulative capacity factors of 18.1%, 24.0%, and 26.8% would fall below the respective PV bin means of 29.5%, 25.5%, and 32.5% (despite the CPV projects' use of dual-axis tracking, which should provide an advantage over the overwhelmingly single-axis PV sample). Based on this comparison to similarly situated PV projects, Hatch in particular seems to be underperforming (at just 18.1%, compared to the PV average of 29.5%). Earlier editions of this report provide additional details about the specifications and performance of the Hatch and Cogentrix Alamosa PV projects.

(overwhelmingly horizontal single-axis east-west tracking, with the exception of four dual-axis tracking projects located in Texas). Tracking boosts average capacity factor by 3-5 percentage points on average (in absolute terms), depending on the resource quartile (i.e., 3% within the 1st resource quartile, 5% in the 4th resource quartile), and 4% on average across all four resource quartiles. This finding that the benefit of tracking increases at higher insolation levels is consistent with results from Bolinger et al. (2016), and also explains why there are many more fixed-tilt (50) than tracking (15) projects in the lowest insolation quartile and many more tracking (50) than fixed-tilt (15) projects in the highest insolation quartile of Figure 14.

- **Inverter Loading Ratio (ILR):** Figure 14 breaks the sample down further into ILR quartiles: <1.21, 1.21-1.26, 1.26-1.32, and ≥1.32. Again, each quartile houses roughly 65 projects, but capacity is concentrated in the third (30%) and fourth (33%) quartiles. The effect of a higher ILR on average capacity factor is noticeable: across all four resource quartiles and fixed/tracking bins, the absolute percentage point difference in capacity factor between the fourth and first inverter loading ratio quartiles is as high as 7% (with an average of 4% across all bins).

Beyond the three drivers depicted in Figure 14, additional explanatory factors, such as array tilt and azimuth, will also play an obvious role in influencing capacity factors, particularly for fixed-tilt projects. Given that we focus only on ground-mounted utility-scale projects, however, our operating assumption is that these two fundamental parameters will tend to be equally optimized across all projects to maximize energy production. Although this assumption may become increasingly tenuous as PV's grid penetration increases,[33] the fact that we lack solid data on project-level tilt and azimuth prevents further analysis of these two fundamental variables at present.

Finally, Figure 15 presents similar information as in Figure 14, but in a slightly different way. Instead of accounting for the strength of the solar resource via insolation quartiles (as in Figure 14), Figure 15 breaks out cumulative capacity factors for both fixed-tilt and tracking projects on a regional basis (with regions as defined earlier in Figure 3)—for those readers who prefer to think geographically rather than in terms of insolation. For the sake of simplicity, Figure 15 also ignores ILR differences. Given what we know about insolation levels regionally (see Figure 3 and Table 2), the results are not surprising: capacity factors are lowest in the Northeast and Midwest and highest in California and the Southwest. Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions (whereas the relatively low-insolation Northeast and Midwest samples include more fixed-tilt than tracking projects).

---

[33] For example, at higher penetration levels, time-of-day pricing factors may shift to more-heavily favor the late afternoon hours, which could encourage developers of fixed-tilt projects to orient them in a more westerly direction.

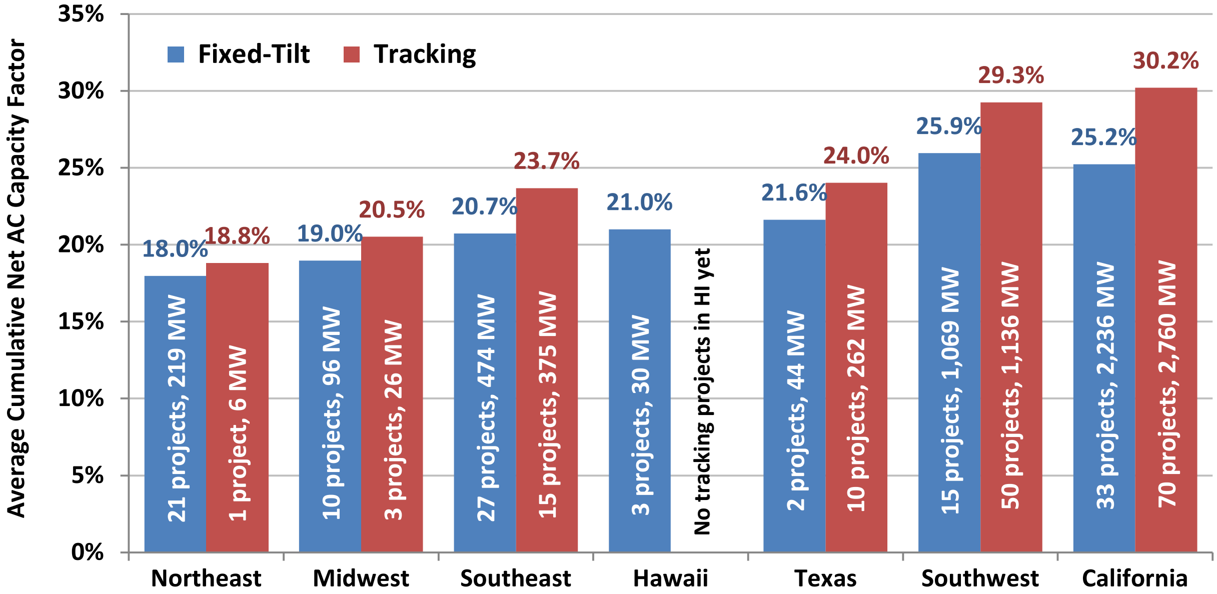


Figure 15. Cumulative Capacity Factor by Region and Fixed-Tilt vs. Tracking

More recent project vintages exhibit higher capacity factors

Although one might initially expect improvements in PV module efficiency over time to boost the capacity factors of more recent project vintages, this is a misunderstanding. As module efficiency increases, developers either use fewer modules to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well) or, alternatively, use the same number of modules to boost the amount of capacity installed on a fixed amount of land (directly reducing at least $/$W_{DC}$ costs, if not also $/$W_{AC}$ costs). As a result, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is, therefore, most likely attributable to a time trend in one of the other variables examined above—e.g., towards higher inverter loading ratios or greater use of tracking, or a buildout of higher insolation sites—as well as performance degradation and perhaps resource variability.

Figure 16 tests this hypothesis by breaking out the average net capacity factor (both cumulative and in 2016) by project vintage across the sample of projects built from 2010 through 2015 (and by noting the relevant average project design parameters within each vintage). Capacity factors have improved gradually and steadily with each new project vintage from 2010 through 2013, driven by commensurate (though in some cases sporadic) increases in each of the three design parameters shown: ILR, percentage of projects using tracking, and GHI. However, 2014- and 2015-vintage projects show essentially no change in average capacity factor from those built in 2013, due to relatively small, and in some cases offsetting, movement in the underlying design parameters.[34]

---

[34] For example, the percentage of newly built projects using tracking increased from 54% in 2013 to 67% in 2015, but the average site-specific long-term GHI declined from 5.29 to 5.11 kWh/m^2/day. Meanwhile, the average ILR drifted only slightly higher, from 1.28 to 1.30.

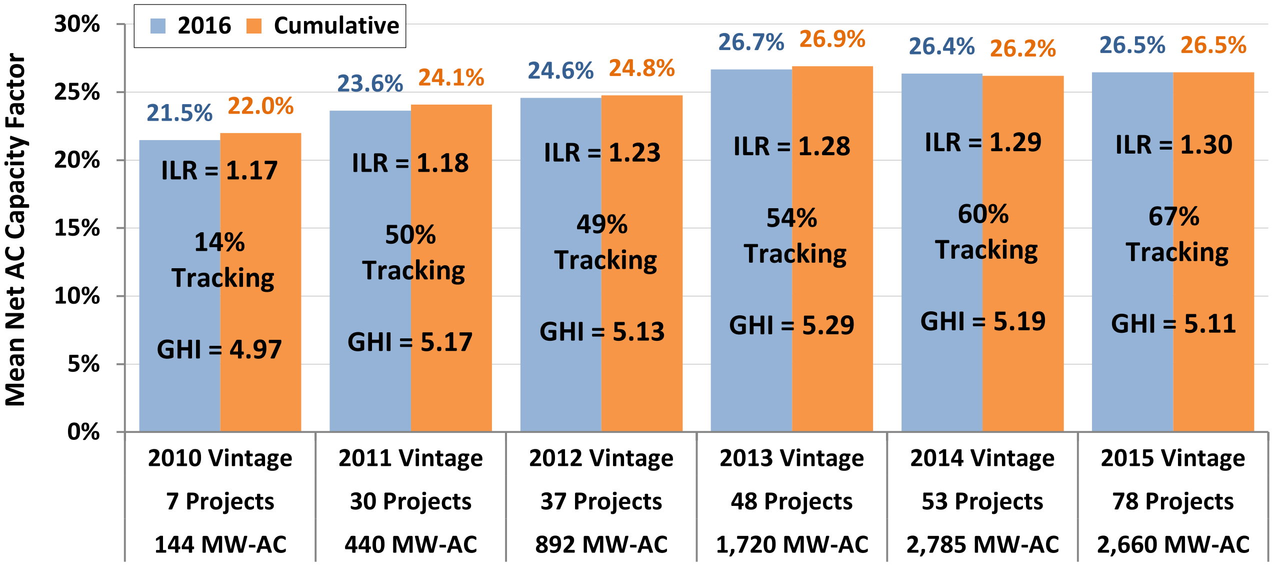


Figure 16. Cumulative and 2016 Capacity Factor by Project Vintage: 2010-2015 Projects

Two other factors could plausibly contribute to the general increase in average capacity factor by vintage (at least through 2013-vintage projects) seen in Figure 16: inter-year variation in the strength of the solar resource and performance degradation over time (as more recent project vintages have had less time to degrade). The former could play a role if insolation at these project sites were significantly stronger in more recent years (e.g., 2015-2016) than in earlier years (e.g., 2011-2014). If this were the case, then 2015-vintage projects, for example, might be expected to exhibit higher cumulative capacity factors than older projects, given that 2016 is the only applicable performance year for a 2015-vintage project.

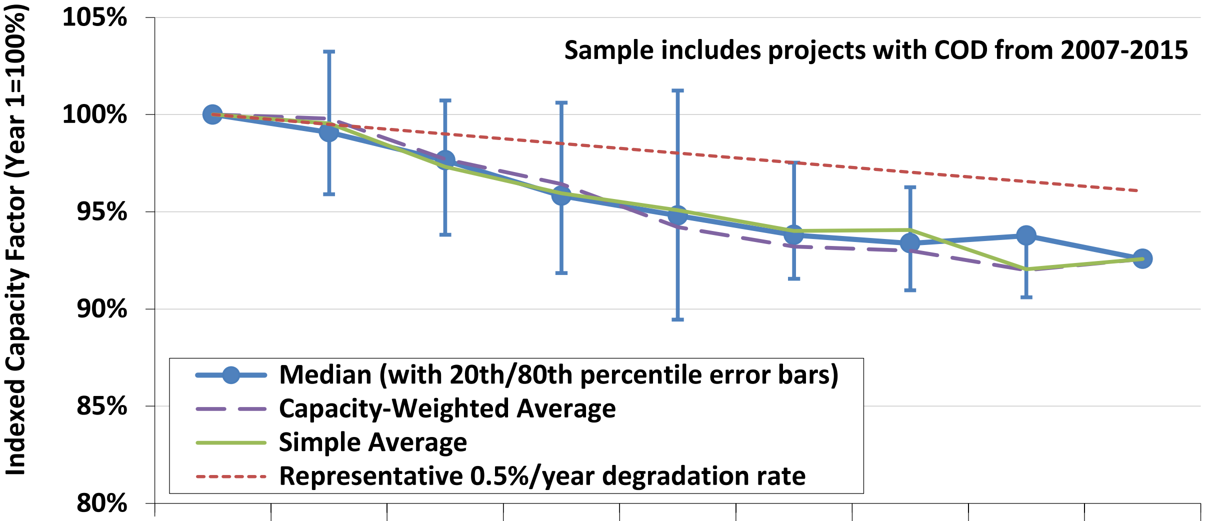
Two findings, however, suggest that inter-year resource variation is *not* contributing to the upward trend seen in Figure 16. First, ex-post annual solar resource data (Vaisala 2013, 2014, 2015, 2017) finds that 2013-2016 were actually *below-normal* (2013-15) or *normal* (2016) insolation years in California and the Southwest, where most utility-scale PV projects are located (65% of the projects and 82% of the capacity in our capacity factor sample are located in these two regions). Second, the blue columns in Figure 16 measure capacity factors across vintages during the same single year—2016—yet show essentially the same upward trend as the orange columns that measure cumulative capacity factors, suggesting that ILR, GHI, and tracking (and perhaps degradation—addressed in the next section) are the true drivers.

Performance degradation is evident, but is difficult to assess and attribute at the project level

Finally, the possibility of performance degradation has been mentioned several times in the preceding text as a potential driver of project-level capacity factors. Unfortunately, degradation is difficult to assess, and even more difficult to attribute, at the project-level, in large part because its impact over limited time frames is likely to be rather modest and swamped by other factors. For example, over a 9-year period (i.e., the maximum number of full calendar years that any project in our sample has been operating to date), a representative degradation rate of

0.5%/year would reduce an initial net AC capacity factor of 30.0% to 28.8% in the ninth year (all else equal). This 120 basis point reduction in capacity factor over nine years is rather trivial in comparison to, and could easily be overwhelmed by, the impact of other factors, such as curtailment or inter-year variation in the strength of the solar resource.

Nevertheless, some amount of degradation is widely expected (e.g., module manufacturers commonly build degradation into their performance guarantees, and many power purchase agreements for utility-scale PV projects also account for degradation when projecting output over time[35]), and so should not be ignored as a possible driver of cumulative capacity factor. To that end, Figure 17 graphs the median (with 20th and 80th percentile bars), simple average, and capacity-weighted average capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).



Years post-COD:	1	2	3	4	5	6	7	8	9
Sample projects:	260	182	129	81	43	13	6	3	1
Sample MW_{AC}:	8,733	6,073	3,288	1,567	667	227	83	29	7

Figure 17. Changes in Capacity Factors Over Time Suggest Performance Degradation

At first glance, Figure 17 suggests that performance degradation has been considerably worse than the 0.5%/year rule of thumb that is commonly assumed (and that is depicted by the dashed red line).[36] However, a number of caveats are in order. First, no attempt has been made to correct for inter-year variation in the strength of the solar resource. Although the potential impact of this omission is likely muted by the fact that year three (for example) for one project will be a different calendar year than year three for another project, inter-year resource variation could still play a role—particularly with several below-normal insolation years in a row, like California and the Southwest reportedly experienced from 2013-15 (Vaisala 2013, 2014, 2015, 2016, 2017).

---

[35] For example, within a sub-sample of 30 utility-scale PV PPAs totaling 3,350 MW_{AC} that were collected for the next section of this report, contractual not-to-exceed degradation rates range from 0.25%-1.0% per year, with a sample mean of 0.6%/year and a median of 0.5%/year.

[36] The fact that the 80th percentile error bar exceeds 103% in year two could partly reflect the initial production ramp-up period that is sometimes experienced by solar projects as they work through and resolve initial "teething" issues during their first year of operations.

Second, curtailment has increasingly affected the output of some solar projects in high penetration markets like California and Hawaii, and could be influencing the trends in Figure 17. As discussed later in the text box on page 35, nearly 235 GWh, or 1.1% of the total potential solar generation within the California ISO market in 2016, was curtailed for one reason or another. To place this amount of curtailed solar energy in perspective, it is equivalent to the annual output of a hypothetical 95 MW_{AC} PV project operating at an average California capacity factor of 28.20%. Absent this curtailment, the average 2016 capacity factor among our California sample would have been more than half a percentage point higher than it was, increasing from 28.20% to 28.75%. This difference in capacity factor is similar to the effect of four years of performance degradation at a rate of 0.5%/year, and could certainly explain some of the apparent degradation seen in Figure 17.

Finally, the project sample is not the same in each year shown along the x-axis of Figure 17, and shrinks rapidly as the number of post-COD years increases, reflecting the relative youth of the utility-scale PV market. This sampling heterogeneity could be complicating interpretation.

In short, though Figure 17 presumably does reflect some amount of module-level performance degradation, other factors such as curtailment and inter-year variation in the strength of the solar resource also likely play a role. Teasing apart these various influences is beyond the scope of this high-level exploration.

2.5 Power Purchase Agreement (PPA) Prices (189 contracts, 11,677 MW_{AC})

The cost of installing, operating, and maintaining a utility-scale PV project, along with its capacity factor—i.e., all of the factors that have been explored so far in this report—are key determinants of a project's levelized cost of energy ("LCOE") as well as the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electric Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale PV projects in the U.S., including 189 contracts totaling 11,677 MW_{AC}. A text box on page 41 also explores the LCOE of utility-scale PV in the United States, and compares it to these empirical PPA prices.

The population from which this PPA price sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, are therefore not included in the sample. We also exclude those projects that unbundle and sell RECs separately from the underlying electricity, because in those instances the PPA price alone does not reflect the project's total revenue requirements (on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons—i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). The same holds true for "avoided cost" contracts with non-negotiated or "standard offer" pricing (also known as "PURPA" or "QF" contracts),[37] which are FiT-like in nature and, in some states, also involve unbundling RECs. In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[38] As such, the PPA price sample comes entirely from utility-scale projects that sell bundled energy, capacity, and RECs to utilities (both investor-owned and publicly-owned utilities) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[39] All that said, projects that do not meet these requirements and so are excluded from the PPA price sample can still contribute to an understanding of utility-scale PV's LCOE, and as such are still included in the LCOE calculations described within the text box on page 41.

---

[37] The Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978 and requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects smaller than 80 MW) at prices that represent their "avoided cost"—i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. In recent years, PURPA has come under fire in some states that are experiencing a large influx of wind and solar projects seeking avoided cost contracts (for more information, see the text box—*Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets*—in the 2014 edition of this report (Bolinger and Seel 2015)).

[38] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[39] Because all of the PPAs in the sample include RECs (i.e., transfer them to the power purchaser), we need not worry too much about REC price trends in the unbundled REC market. It is, however, worth noting that some states have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for RPS compliance purposes), while others have implemented solar "set-asides" or "carve-outs" (requiring a specific portion of the RPS to be met by solar) as a way to encourage solar power development specifically. In these instances, it is possible that utilities might be willing to pay a bit more for solar through a bundled PPA than they otherwise would be, either because they need to in order to comply with a solar set-aside, or because they know that each bundled solar REC has added value (in the case of a multiplier). So even though REC prices do not directly

For each of the contracts in the sample,[40] we have collected the contractually locked-in PPA price data over the full term of the PPA,[41] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[42] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum amount of revenue required by[43]) these projects over the life of the contract—at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation)[44] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[45,46] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized LCOE; the text box on page 41 calculates the latter and

---

affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases—presumably to the upside.

[40] In general, each PPA corresponds to a different project, though in some cases a single project sells power to more than one utility under separate PPAs, in which case two or more PPAs may be tied to a single project.

[41] The minimum PPA term in the sample is 3 years, though this contract (along with several other short-term contracts like it) covers just the first few years of a project that has a longer-term PPA with a different counterparty starting in 2019. The maximum PPA term is 34 years, the mean is 22.5 years, the median is 21.0 years, and the capacity-weighted average is 22.9 years.

[42] In cases where PPA price escalation rates are tied to inflation, the EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2016* is used to determine expected escalation rates. For contracts that use time-of-delivery pricing and have at least one year of operating history, each project's average historical generation profile is assumed to be replicated into the future. For those projects with less than a full year of operating history, the generation profiles of similar (and ideally nearby) projects are used as a proxy until sufficient operating experience is available.

[43] In a competitive "cost-plus" pricing environment—where the PPA price is just sufficient to recoup initial capital costs, cover ongoing operating costs, and provide a normal rate of return—PPA prices will represent the minimum amount of revenue required by a project. In contrast, "value-based" pricing occurs when the project developer or owner is able to negotiate a higher-than-necessary PPA price that nevertheless still provides value to the buyer.

[44] In addition to the other federal incentives listed, eleven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee did not affect the PPA price.

[45] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher (i.e., 30%/(1 minus the federal tax rate)) if there were no federal investment tax credit ("ITC"). Without the ITC, however, the resulting increase in PPA prices would be mitigated by the fact that sponsors with tax appetite could then leverage up their projects more heavily with cheap debt, while sponsors without tax appetite would be able to forego expensive third-party tax equity in favor of cheaper forms of capital, like debt. Because of these financing shifts, the PPA price would not increase by 50%, but rather more like 35-40% in the case of a sponsor with tax appetite, and by roughly 20% in the case of a sponsor without tax appetite that currently relies on third-party tax equity to monetize the ITC (Bolinger 2014).

[46] Though there is too much variety in state-level incentives to systematically quantify their effect on PPA prices here, one example is New Mexico's refundable Production Tax Credit, which has provided a credit of varying amounts per MWh (averaging $27/MWh) of solar electricity produced over a project's first ten years. One PPA for a utility-scale PV project in New Mexico allows for two different PPA prices—one that is $43.50/MWh higher than the other, and that goes into effect only if the project does not qualify for the New Mexico PTC. Based on New Mexico's top corporate tax rate of 7.6%, a $43.50/MWh price increase due to loss of New Mexico's PTC seems excessive (a more appropriate 20-year adjustment would seemingly have been roughly half that amount), but nevertheless, this is one tangible example of how state incentives can reduce PPA prices.

compares it to the former, and finds that PPA prices are consistently lower than LCOE estimates, as expected.

PPA prices have fallen dramatically, in all regions of the country

Figure 18 shows trends in the levelized (using a 7% real discount rate) PPA prices from the full PV contract sample over time. Each bubble in Figure 18 represents a single PPA, with the color of the bubble representing the region in which the underlying project is located,[47] the area of the bubble corresponding to the size of the contract in MW_{AC}, and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[48]

Figure 19, meanwhile, is essentially the same as Figure 18, except that it focuses only on those PPAs that were signed since the start of 2015. The purpose of Figure 19 is to provide greater resolution on the most-recent time period, which otherwise appears a bit crowded in Figure 18.

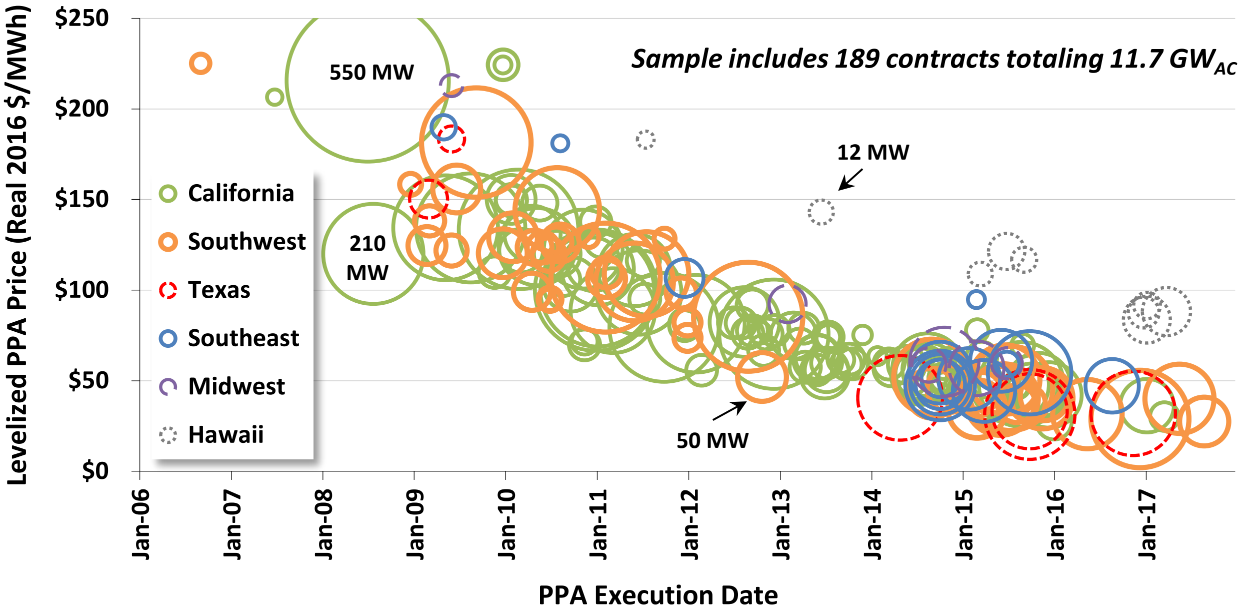


Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

---

[47] Figure 18 excludes the single northeastern PPA in our sample—a 32 MW_{AC} project on Long Island that was signed in June 2010 and that has a real levelized price of ~$290/MWh (in 2016 dollars)—and we do not yet have PPA price data for any projects in the northwest region.

[48] Because PPA prices reflect market expectations at the time a PPA is executed—which could be two years or more in advance of when the project achieves commercial operation—the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices. For those interested in viewing average PPA prices by commercial operation date, however, Figure 21 breaks it out both ways.

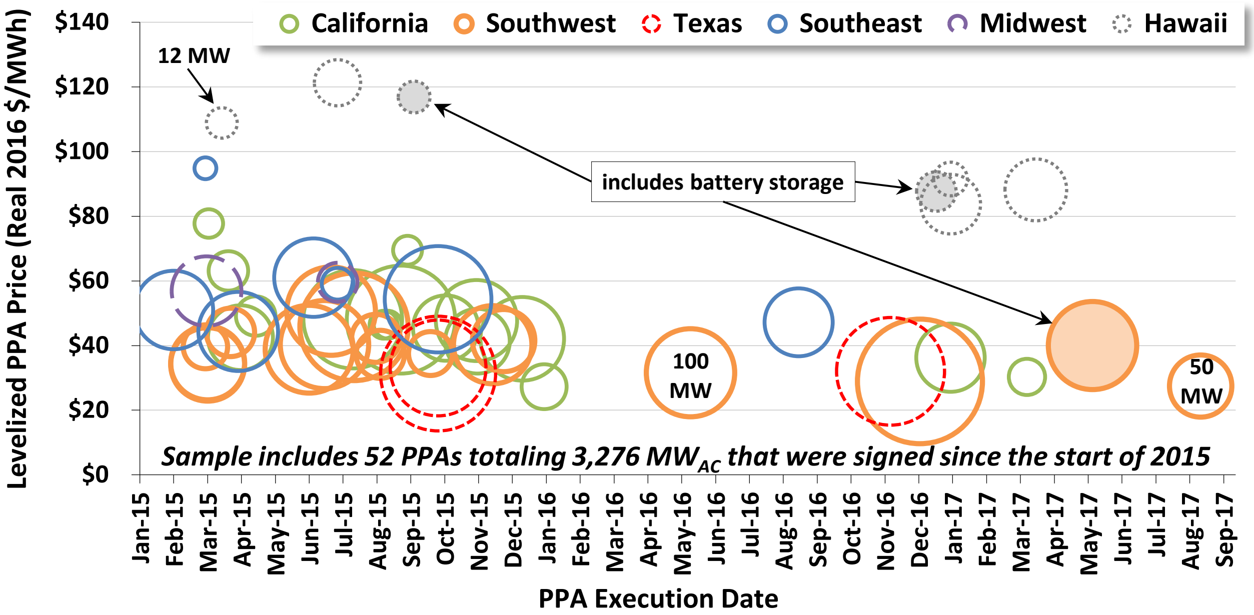


Figure 19. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2015-2017 (YTD) Contracts Only

A number of aspects of Figures 18 and 19 are worth highlighting:

- ***PPA pricing has declined steadily and significantly over time.*** As recently as 2011, solar PPA prices in excess of $100/MWh were quite common. Five years later, most PPAs in the sample are priced at or below $50/MWh levelized (in real, 2016 dollars), with a few priced as aggressively as ~$30/MWh. Though this price decline is impressive in terms of both scale and pace, it is also worth noting that in some markets with high solar penetration, the *wholesale market value* of solar energy has also declined over time as solar penetration has increased; the text box on page 35 explores this value decline within the United States' largest solar market, California.

- ***Though California and the Southwest still dominate the sample, the market has expanded to other regions in recent years.*** Among the sub-sample of PPAs executed *after* 2013, 67% of the contracts representing 63% of the capacity are for projects located in either California or the Southwest, down significantly from 91% of the contracts representing 97% of the capacity within the sub-sample of PPAs executed *prior to* 2014. New markets include the Southeast (17% of post-2013 capacity in the sample), Texas (12%), Hawaii (4%), and even the sun-challenged Midwest (4%). With the exception of Hawaii, all other regions shown in Figures 18 and 19 feature PPA prices below $60/MWh.

- ***Hawaiian projects are priced at a significant premium.*** This year, for the first time, we include Hawaiian projects in our PPA price sample. As can be clearly seen in both Figures 18 and 19, Hawaiian PPAs have consistently been priced at a significant premium—of at least $40/MWh—over those in the continental United States. Although some premium is no doubt warranted given Hawaii's remote location and weaker solar resource (at least relative to California and the Southwest), the ~$40/MWh PPA price premium seen in recent years seems high. For example, Fu et al. (2015) modeled the LCOE of utility-scale PV projects throughout the United States (including Hawaii), based on differences in labor rates, installation costs, insolation, and other factors, and estimated that in 2015, a project in Kona, Hawaii would have had an LCOE that was \$14-\$15/MWh higher than an identical project in California's Imperial Valley, and only \$7-\$8/MWh higher than an identical project in Bakersfield, California. The observed levelized PPA price premium of ~\$40/MWh is considerably higher than these modeled LCOE premiums, and perhaps suggests that some degree of value-based (as opposed to cost-based, or cost-plus) pricing may be occurring in Hawaii, with developers bidding to some extent against the high cost of oil-fired generation.

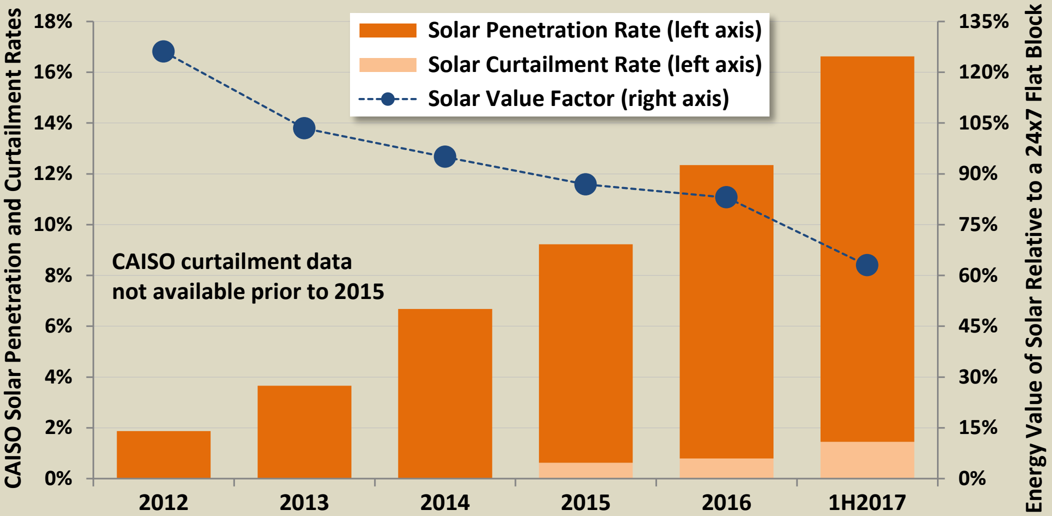
- ***The incremental cost of storage does not seem prohibitive.*** Also for the first time, this year our sample includes three projects designed and built with long-duration (i.e., 4-5 hours) battery storage. These three projects are distinguished in Figure 19 by having their bubbles shaded (and, more obviously, by the indicative label with arrows). Each of these projects (plus a fourth for which PPA price information is not yet available) are discussed in more detail in the text box on page 37, but here we simply note that these utility-scale PV plus storage projects do not seem to be priced at a significant premium compared to other contemporary projects located within the same region but lacking storage. This theme is explored further in the text box on page 37.
- ***Smaller projects are often equally competitive.*** Though there have recently been a number of large, low-priced contracts announced, smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are, in some cases, seemingly just as competitive as larger projects. In many states, very large projects may face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.
- ***Not all of these projects are online, but barring a trade war, there is no compelling reason to think that they will not be built.*** Unlike other chapters of this report, which focus exclusively on operating projects (determined by commercial operation date), this chapter tracks PPA prices by *contract execution date*—which means including projects that are still in development—in order to provide a better picture of where the market is (or was) at any given point in time. As of August 2017, more than 90% of all projects and capacity within the PPA sample were either partially or fully operating, with the remainder representing more-recently signed contracts for projects that are still under development or construction. While it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown in Figures 18 and 19, the sample does not include any PPAs that have already been terminated.[49] One prominent variable in this equation is the still-to-be-determined outcome of the so-called "Section 201" trade petition to impose tariffs on imported PV modules; a successful petition could potentially increase costs for those projects that have not yet secured modules (Berg, Barati, and Wilkinson 2017), possibly leading to PPA renegotiations or even outright cancellations.

---

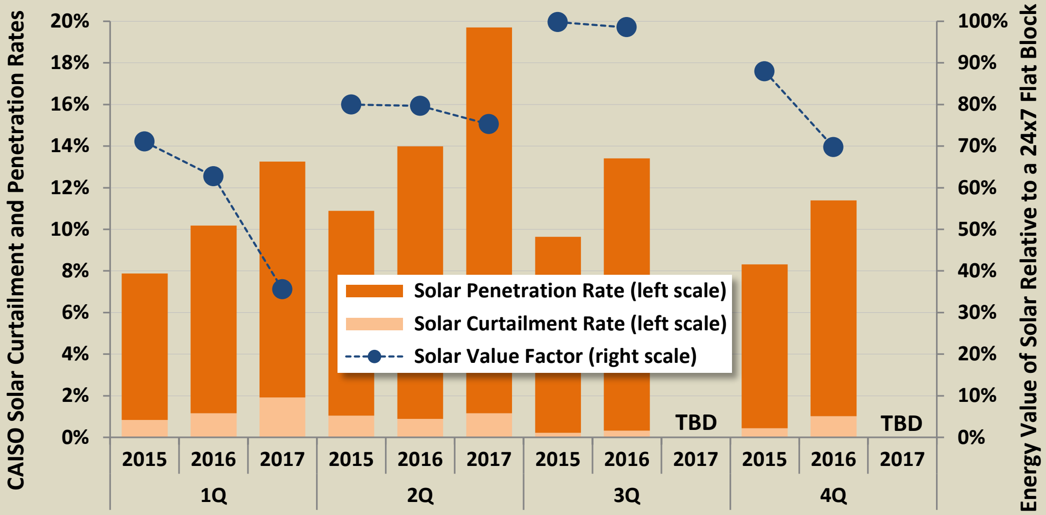
[49] There is a history of solar project and PPA cancellations in California and elsewhere, though in many cases these have involved projects using less-mature technologies (e.g., Stirling dish engines, compact linear Fresnel reflectors, and power towers). For PV projects, price revisions are perhaps a more likely risk than outright termination.

The energy value of solar has declined in America's largest solar market

Solar energy penetration (including estimates for DG solar) within the CAISO market increased from nearly 2% of load back in 2012 to more than 12% in 2016, and has increased even further so far in 2017. As solar penetration has risen, so too has the percentage of solar generation that is being curtailed—still in the low single digits (thanks in part to the west-wide energy imbalance market), but rising since data first became available in 2015.



Perhaps more worrisome, the wholesale energy value of solar within CAISO's real-time market (expressed in the two graphs here as a percentage of the simple average wholesale power price across all hours) has declined steadily. Back in 2012, when solar covered just 2% of load, the hourly generation-weighted average wholesale power price earned by solar was $38.0/MWh, or 126% of the simple average wholesale power price across all hours. Four years later in 2016, with solar at 12% penetration, solar's value was just $23.8/MWh, or 83% of the average wholesale price. With penetration and curtailment increasing further in 2017, this value decline is likely to continue—analysis of the first half of the year finds solar's value at $15.8/MWh, or just 63% of the average wholesale price of $25.1/MWh. That said, the bottom graph shows that the third and fourth quarters are typically higher-value quarters than the first and second, suggesting that the full-year 2017 numbers might not be as dire as suggested by the H1 numbers shown in the top graph.



Breaking the numbers out on a quarterly basis reveals that after a dismal 1Q17—attributable in part to a "flood" of hydropower generation—2Q17 has not been as troublesome, with curtailment on par with both 2015 and 2016 (at least in percentage terms) and solar's energy value only down slightly from prior years (despite much higher penetration in 2Q17). It remains to be seen how the 3rd and 4th quarters—typically higher-value quarters—will round out the year.

It should be noted that the decline in the value of solar in California is not necessarily indicative of other markets across the United States. Solar's energy market value depends on a variety of factors, including local solar penetration levels, electricity demand and supply patterns, and the flexibility of other generators to ramp their production up and down. For example, in ERCOT and SPP—the only two other ISOs in the country that report solar generation separately—solar's energy value in 2016 was 131% and 133% of average wholesale power prices, respectively (albeit at much lower large-scale solar penetration levels of 0.24% and 0.08%).

Figure 20 portrays the data from Figure 18 in a slightly different way, to more clearly illustrate the strong downward time trend in average pricing. The circle markers show the levelized PPA price of each individual contract grouped by the year in which the contract was signed (each circle in Figure 20 corresponds to a bubble in Figure 18; Hawaii PPAs are shaded here in orange), while the blue-shaded columns show the generation-weighted average of those individual levelized contract prices. Levelized PPA prices for utility-scale PV projects within the sample consistently fell by $20-$30/MWh per year on average from 2006 through 2012, with smaller price declines averaging ~$10/MWh from 2013 through 2016.[50] The uptick in the average price among contracts executed so far in 2017 is likely attributable to the small size and make-up of the sample: three of these seven PPAs (totaling 110 MW) are for Hawaiian projects (with their apparent premium), while a fourth 100 MW project includes battery storage and would reportedly have been priced $15/MWh lower if just solar without storage (this project is described further in the text box on the next page).

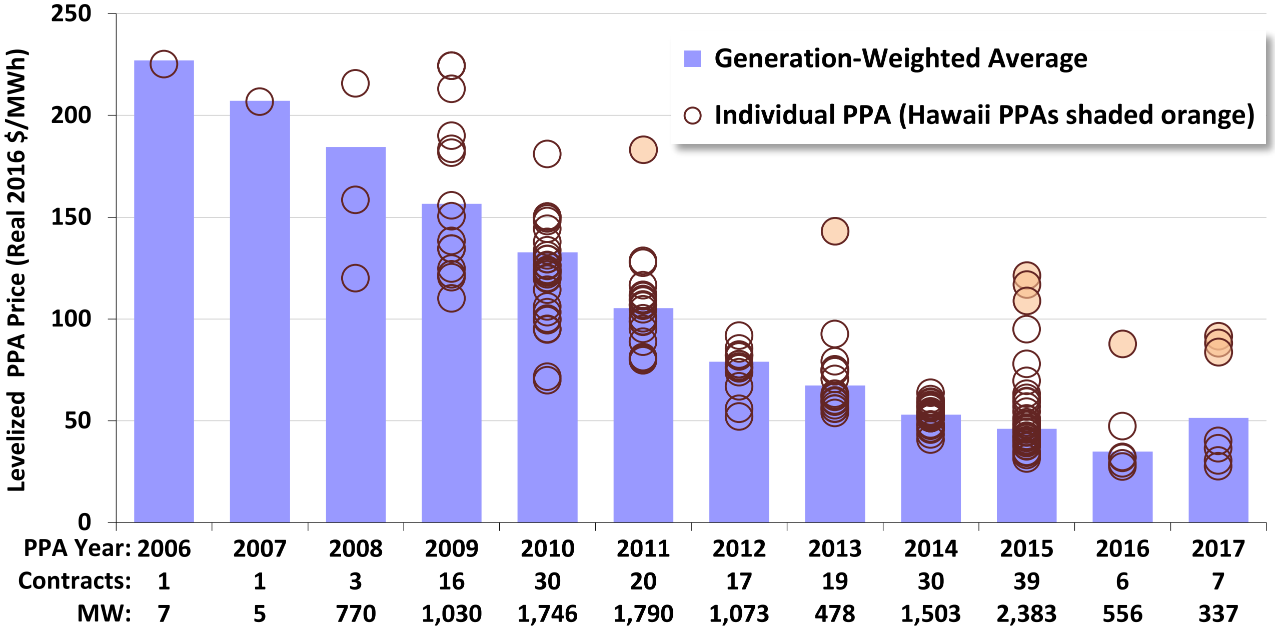


Figure 20. Levelized PV PPA Prices by Contract Vintage[51]

---

[50] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength, tracking versus fixed-tilt, inverter loading ratio, and module type. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PPAs in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Section 2.2) that are recouped over time through greater energy yield (see Section 2.4), thereby potentially leaving the net effect on PPA prices largely a wash.

[51] Figure 20 excludes the two CPV projects in our sample. If included, they would both fall within the 2010 bin, at levelized prices of $109.4/MWh and $126.9/MWh—i.e., within the range of PV projects shown.

Utility-scale PV plus battery storage starting to gain traction

To date, four integrated utility-scale PV plus battery storage projects have been announced in the United States—two in Hawaii (on the island of Kauai) and two in Arizona—with one of the Kauai projects having achieved commercial operation in early 2017. The table below provides known specs on each of these four projects/contracts, all of which will use lithium-ion technology (with at least two, and most likely three, deploying Tesla Powerpacks).

State	Project		Capacity (MW-AC)		Battery Storage		PPA Date	Expected COD	PPA Term (years)	PV Mount	Expected Capacity Factor	Levelized PPA Price (2016 $/MWh)	% of PV used to charge
	Sponsor	Offtaker	PV	Battery	Duration	MWh							
HI	Tesla	KIUC	13	13	4 hours	52	Sep-15	Apr-17	20	Fixed	~20%	~$117	>80%
HI	AES	KIUC	20	20	5 hours	100	Dec-16	Oct-18	25	Tracking	~29%	~$88	>70%
AZ	NextEra	SRP	20	10	4 hours	40	Apr-17	Mar-18	20	Tracking	~33%	N/A	~25%
AZ	NextEra	TEP	100	30	4 hours	120	May-17	Dec-19	20	Tracking	~33%	~$40	~15%

It should come as no surprise that the first two such PPAs are for projects located in an island state with an isolated grid and already-significant solar penetration. Commensurately, both Kauai projects size the battery capacity to match the PV capacity (in AC terms), and will use 70-80% (or more) of the solar energy generated in order to charge the batteries (for later discharge during evening hours). This stands in contrast to the two Arizona projects, which feature battery capacities that are 30-50% of the PV capacity (in AC terms), and that will use only 15-25% of the solar output for charging.

Levelized PPA prices are available for three of the four projects. In Kauai, the second PPA (signed roughly 16 months after the first) is priced about $30/MWh lower than the first, though is also 5 years longer in duration (which reduces the levelized price somewhat). That said, as shown in Figure 19 of the main report, PPA prices for utility-scale PV projects *without* storage in Hawaii appear to have fallen by a similar amount over this same time frame. In fact, based on Figure 19, there does not seem to be an obviously discernible difference in Hawaii between the PPA prices of projects with or without storage—an assessment that is perhaps clouded by any value-based pricing that might be occurring (as suggested in the text below Figure 19).

On the mainland, there is only one publicly available PPA price data point at present: Tucson Electric Power's (TEP's) announcement that its all-in cost will be "significantly less than" $45/MWh, and that the solar component is less than $30/MWh on its own (Maloney 2017), implying an adder of ~$15/MWh for 4 hours of storage at 30% of PV nameplate. This implied adder is consistent with NextEra's recent projection of a battery storage adder (for 4 hours at 40% of solar nameplate) of $19-29/MWh in 2016, dropping to $12-22/MWh in 2020 (NextEra Energy 2017). In the wake of the TEP announcement, ViZn Energy (a zinc-iron flow battery manufacturer) heralded its own ability to build a similar project for under $40/MWh, with a storage adder (for 4 hours at 30% of solar nameplate) of ~$14/MWh (ViZn Energy 2017).

This discussion surrounding the size of the storage adder naturally raises the question of whether the benefit of storage outweighs the incremental cost. A relatively simple modification of the solar generation data used for the analysis highlighted in the "declining energy value of solar" text box on page 35 suggests that storage is not yet cost-effective—at least in California, and considering only the value of the 4-hour energy shift—at these adder levels. Scaling the actual hourly PV generation profile down to a hypothetical 100 MW project, we subtracted 30 MW of PV generation per hour over a 5-hour period (i.e., 150 MWh total) in the middle of each day (from 10 AM-3 PM) and then added back 30 MW per hour over a 4-hour period (i.e., 120 MWh total) later in the day (from either 4-8, 5-9, or 6-10 PM—we looked at all three periods). The disparity between the 150 MWh charge and 120 MWh discharge is a crude attempt to account for an 80% round-trip efficiency. The results suggest that, at least in California, such an energy shift would have only increased the wholesale energy value of solar by ~$3/MWh in 2016—i.e., only ~20% of the indicative adder cost.

Of course, California is not Arizona; although California's "duck curve" gets all the attention, Arizona's duck curve is reportedly "far more dramatic" due to the predominant role that solar plays in that state, relative to other renewables (Maloney 2017). As such, a 4-hour energy shift may be more valuable in Arizona than it is in California. In addition, Denholm et al. (2017) point out that although PV plus battery storage was not cost-competitive with PV alone in California in 2016, the reverse will be true by 2020 as solar penetration increases. Especially for long-lived technologies (and investment decisions), such forward-looking modeling is more appropriate than a single-year historical assessment. Finally, there are other grid services—and corresponding value or revenue streams—that a battery can provide, but that are not accounted for in this back-of-the-envelope modeling exercise (which focuses solely on the 4-hour energy shift). For example, accounting for capacity value, frequency regulation, and reserves could all bolster the benefit side of the equation.

As noted earlier, some projects in our PPA price sample have not yet been built, and for those that have been built often a year or more can pass between when a PPA is signed and when the underlying project ultimately achieves commercial operation. As a result, the decline in PPA prices over time looks more erratic when viewed by commercial operation date (rather than by PPA execution date). The blue columns in Figure 21 are based on PPA execution date (and thus match those shown in Figure 20), while the orange columns show the generation-weighted average PPA price in the years in which each project achieved full commercial operation. Because 2017 is still in progress, it is labeled as provisional.[52] Though the average levelized price of PPAs signed in 2016 is ~$35/MWh, the average levelized PPA price among projects that came online in 2016 is significantly higher at ~$59/MWh; this difference was even starker in many prior years.

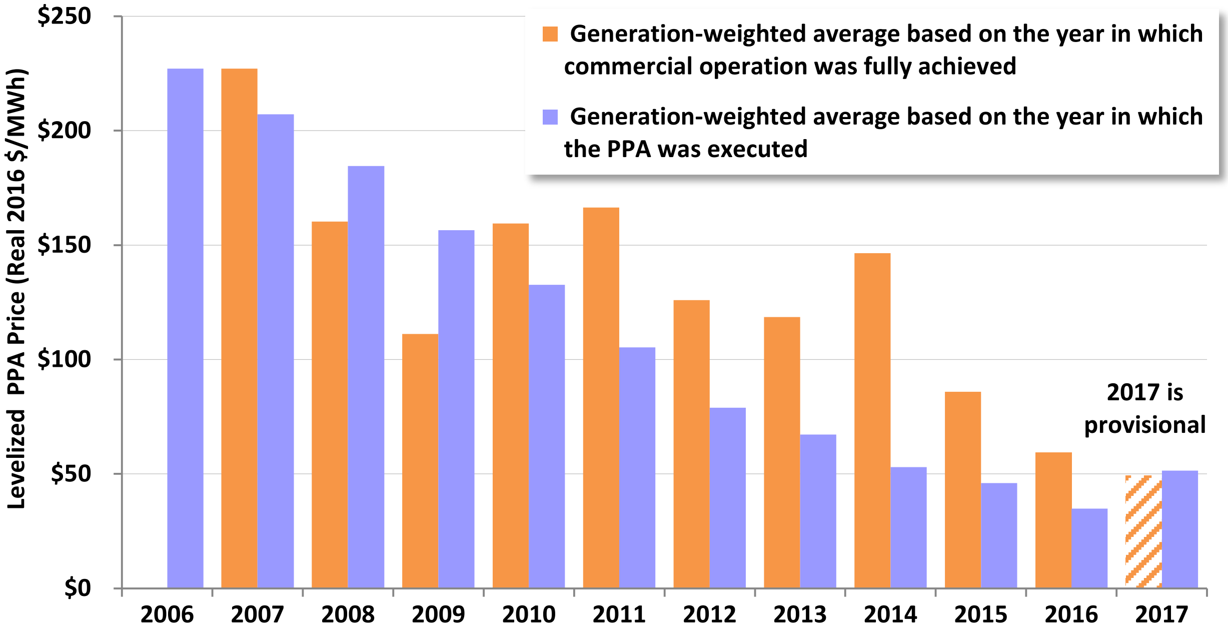


Figure 21. Average Levelized PV PPA Prices by Contract and COD Vintage

Solar's largely non-escalating and stable pricing can hedge against fuel price risk

Roughly two-thirds of the contracts (and capacity) in the PPA sample feature pricing that does *not* escalate in nominal dollars over the life of the contract—which means that pricing actually *declines* over time in real dollar terms. Figure 22 illustrates this decline by plotting over time, in real 2016 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts). In other words, for each contract vintage, Figure 22 shows the stream of generation-weighted average PPA prices over time (these are the future PPA price streams that were levelized to yield the blue-shaded columns in Figures 20 and 21).

---

[52] Though, for that matter, 2016 and earlier years are also still provisional in some sense, given that our sample of older PPAs will no doubt increase in future years as well, as more light is shed on pricing over time.

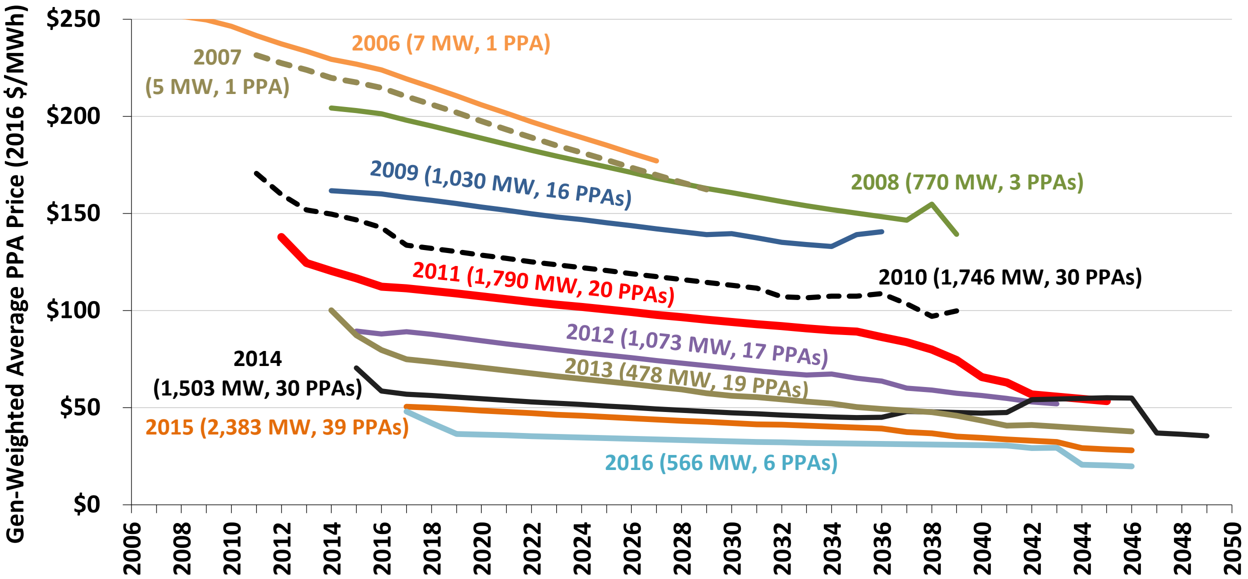


Figure 22. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide buyers with a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013, 2017). Figure 23 illustrates this potential by plotting the future stream of average and median PV PPA prices from 29 contracts in the sample that were executed over the past two years (i.e., from July 2015 through August 2017) against a range of projections of *just the fuel costs* of natural gas-fired generation.[53] In this way, Figure 23 essentially compares the cost of *new* PV projects to the cost of *existing* gas-fired generation. This comparison is not perfect, however, given that existing gas-fired generators will also incur some small amount of non-fuel variable operating costs that are not accounted for, and may also still need to recover some portion of their initial capital costs to build the project. Nor do natural gas and solar projects have equivalent output profiles or environmental characteristics.

Nonetheless, as shown, both the generation-weighted average and median PPA prices start out well above the range of fuel cost projections in 2017, but decline (in real 2016 $/MWh terms) over time, entering the fuel cost range in 2021 and 2022, respectively, and eventually reaching the reference case fuel cost projection by the end of that decade before ultimately falling below the reference case projection by the second half of the 2030s.

---

[53] The national average fuel cost projections come from the EIA's *Annual Energy Outlook 2017* publication, and increase from around $3.53/MMBtu in 2017 to $6.13/MMBtu (both in 2016 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low and high (respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the average heat rates implied by the modeling output, which start at ~ 7.9 MMBtu/MWh in 2017 and gradually decline to ~6.9 MMBtu/MWh by 2050.

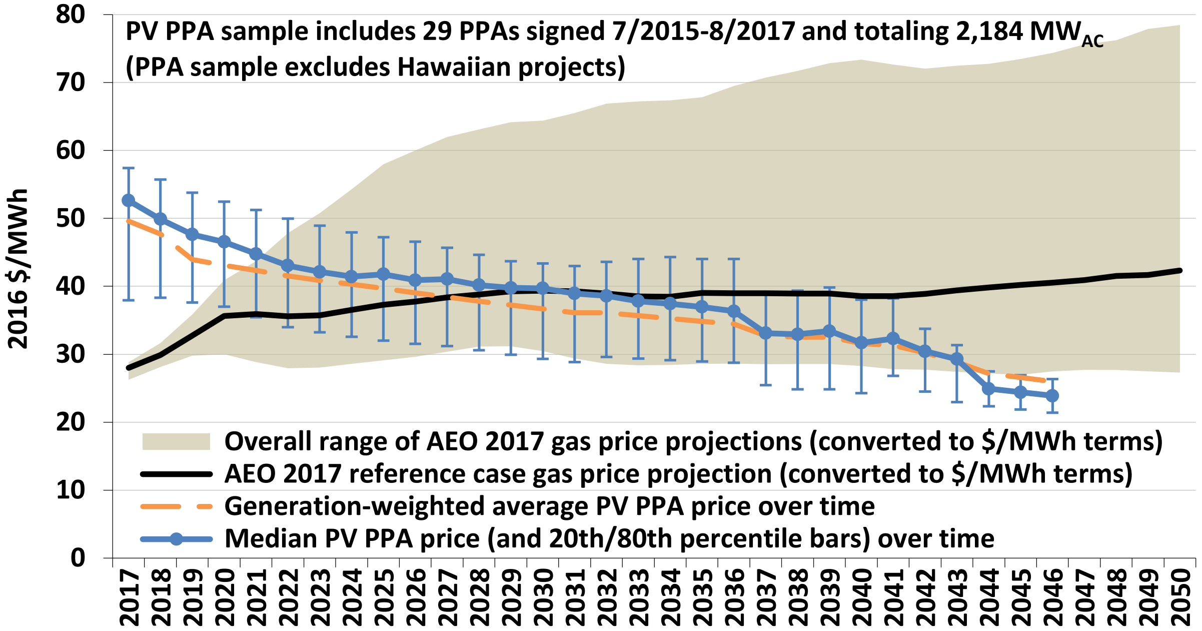


Figure 23. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

On a levelized basis (in real 2016 dollars) from 2017 through 2046, the PV PPA prices come to $41.6/MWh (median) and $39.5/MWh (generation-weighted average), compared to $36.2/MWh for the reference case fuel cost projection, suggesting that sustained low gas prices (and low gas price expectations) has made it difficult for PV to compete with *existing* gas-fired generation. That said, it is important to recognize that the PV PPA prices shown in Figure 23 have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain—actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases (Bolinger 2013, 2017).

Moreover, as noted above, the comparison laid out in Figure 23 is not entirely apples-to-apples, as it does not include the recovery of fixed capital costs that would be incurred by *new* gas-fired generators (or other non-fuel operating costs that would be incurred by both new and existing gas-fired generators), whereas the PV PPA prices are set at a level intended to be sufficient to recover *all* costs (i.e., both initial capital costs and ongoing operating costs). By one estimate, capital and non-fuel O&M costs can add $27-$54/MWh to the levelized cost of energy from a combined-cycle gas plant (Lazard 2016).

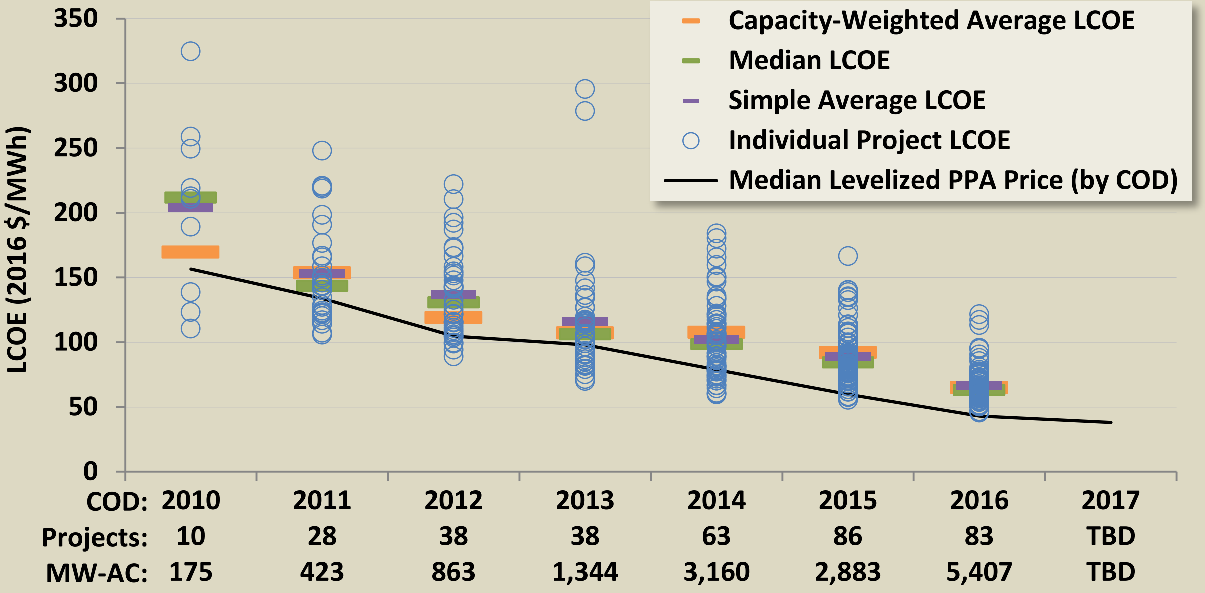
On the other hand, Figure 23 also makes no attempt to account for the operational and environmental differences between these two generation sources, or the differences in federal and state subsidies received. In particular, it is widely known that the market value of solar declines with increased solar penetration, as a result of grid integration challenges and other characteristics related to its temporal generation profile (Mills and Wiser 2013); these factors are not considered here (but are partially explored, at least within California, in the text box on page 35).

Levelized PPA prices track the LCOE of utility-scale PV reasonably well

In a competitive market, bundled long-term PPA prices can be thought of as reflecting a project's levelized cost of energy (LCOE) reduced by the levelized value of any state or federal incentives received. Hence, as a first-order approximation, project-level LCOE can be estimated simply by adding the levelized value of incentives received to levelized PPA prices. LCOE can also be estimated more directly, however, from key project data such as collected for this report—e.g., CapEx, capacity factor, and OpEx—coupled with other assumptions about financing, taxes, etc. One advantage of this more-direct approach is that it enables us to estimate LCOE for a much larger sample of projects than would be possible if starting with PPA prices. Here we use the project-level empirical data reflected throughout this report, in conjunction with other assumptions enumerated in the next paragraph, to estimate the LCOE of utility-scale PV by project and on average over time.

Our sample starts with the >14 GW_{AC} of projects for which we have compiled CapEx estimates (as presented in Section 2.2). For projects that have been operating for at least a full year and for which we have capacity factor data (as presented in Section 2.4), we rely on those empirical data. For projects where we do not yet have capacity factor data, we estimate capacity factors based on underlying project characteristics (e.g., the average long-term irradiance at the project site, whether or not tracking is used, the ILR, etc.) in conjunction with the regression formula laid out in Bolinger, Seel, and Wu (2016). In all cases, we then handicap the project-level capacity factor data to reflect a projected annual degradation rate of 0.5%/year (see footnote 35) before plugging it into the LCOE equation (which is the same equation used in Cole et al. (2016)). Total OpEx is assumed to be $30/kW-year for all projects; this assumption is higher than the average utility O&M cost numbers shown in Figure 13, but those numbers are derived from FERC Form 1 and do not reflect total OpEx (see footnote 24). The cost of equity is assumed to be 10% (after-tax) for all projects, while the cost of debt varies daily (but is averaged across each calendar year) based on the 30-year fixed-for-floating swap rate benchmark (ICE 2017) plus BNEF's (2017) estimate of the debt spread in the commercial bank market over time. The nominal after-tax weighted average cost of capital, or WACC, reflects a 60%/40% debt/equity ratio in all cases, applied to the average cost of debt and equity *in the year prior to* when each project achieves commercial operation (in an attempt to reflect the time lag between when a project is financed and built). For reference, the nominal after-tax WACC ranges from 6.46% in 2009 (for projects with a 2010 COD) to 5.66% in 2015 (for projects with a 2016 COD). Other assumptions include a 30-year project life, an inflation rate of 2.5%/year, a combined federal and state tax rate of 40%, a 5-year MACRS depreciation schedule, ***and NO investment tax credit (ITC)***. Finally, the "capital recovery factor" and "project finance factor" are calculated (from various data and assumptions already noted above) per the formulas in Cole et al. (2016).

The figure below shows the results of this exercise, with both project-level and central estimate LCOEs plotted alongside median levelized PPA prices (from a smaller sample than indicated for LCOE, and in this case levelized over 30 years to match the LCOE term and then plotted by COD, rather than execution, year). In general, the central LCOE estimates closely follow the declining PPA price trend seen here (and elsewhere in this section), suggesting a relatively competitive market for PPAs. Median PPA prices are universally lower than the central LCOE estimates because of the value of the 30% ITC (plus any state-level incentives), which is passed through to offtakers in the form of lower prices (by ~$20/MWh in recent years). Looking ahead, the median levelized PPA price among a small sample of 11 projects totaling 427 MW that are likely to achieve commercial operations in 2017 suggests a further decline in LCOE.



3. Utility-Scale Concentrating Solar Thermal Power (CSP)

This chapter largely follows the same format as the previous chapter, but focuses on CSP rather than PV projects.[54] Isolating these two different technologies in this way simplifies reporting and enables readers who are more interested in just one of these technologies to more-quickly access what they need. So as not to lose the value of being able to easily compare the two technologies when presented side by side, however, we have endeavored to include reference data points from our PV sample in many of the CSP-focused graphs in this chapter.

Because no new CSP plants were built (or were under construction, or even officially announced) in the United States in 2016, only the capacity factor section (Section 3.3) contains new data—i.e., capacity factors in 2016—compared to last year's edition of this report. That said, all other sections have been updated (e.g., by adjusting dollar years, by adding or revising relevant commentary) as appropriate.

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1,781 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough buildout in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed a few years later by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida).

A more-concentrated burst of CSP deployment occurred in the three-year period from 2013 to 2015. In 2013, the 250 MW_{AC} Solana trough project, which includes 6 hours of molten salt storage capacity, came online in Arizona. In 2014, three additional CSP projects came fully online in California: two more trough projects (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale "solar power tower" project in the United States (Ivanpah at 377 MW_{AC}); none of these three projects includes thermal storage. A second 110 MW_{AC} solar power tower project with 10 hours of built-in thermal storage—Crescent Dunes in Nevada—finished major construction activities in 2014 and became commercially operational in 2015.

In the wake of this buildout—totaling 1,237 MW_{AC}—of new CSP capacity from 2013-2015, no other utility-scale CSP projects have been built in the United States, nor are any projects moving towards construction. Moreover, two of the oldest CSP plants in the United States—SEGS I and II, which came online in the mid-1980s—were decommissioned in 2015, following 30 years of service. The remaining SEGS plants (III-IX) are owned by a different entity and continue to operate.

---

[54] One notable exception is that this chapter does not include a section on O&M prices. As noted in Section 2.3, we only have empirical O&M cost data for a single CSP project (the 75 MW_{AC} Martin trough project in Florida), and so opted to present those data along with the PV O&M cost data in Figure 13.

Figure 24 overlays the location of each utility-scale CSP project on a map of solar resource strength in the United States, as measured by direct normal irradiance ("DNI"), which is a more appropriate measure of insolation than GHI for CSP projects.[55] With the exception of the 2010 project in Florida (75 MW$_{AC}$), all other CSP projects in the United States have been deployed in California (1,237 MW$_{AC}$) and the Southwest (250 MW$_{AC}$ in Arizona and 179 MW$_{AC}$ in Nevada), where the DNI resource is strongest.

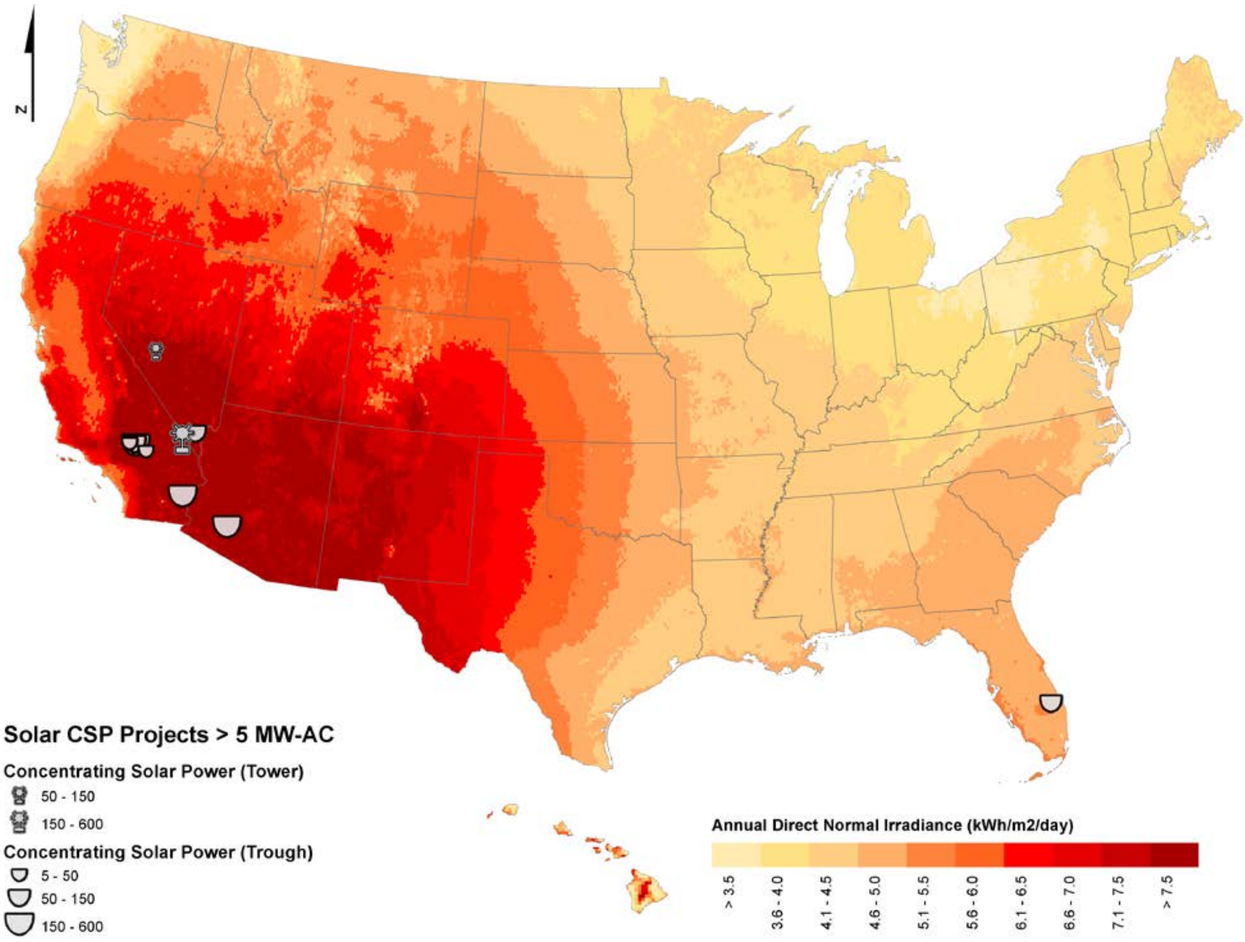

N
Solar CSP Projects > 5 MW-AC
Concentrating Solar Power (Tower)
50 - 150
150 - 600
Concentrating Solar Power (Trough)
5 - 50
50 - 150
150 - 600
Annual Direct Normal Irradiance (kWh/m2/day)
> 3.5
3.6 - 4.0
4.1 - 4.5
4.6 - 5.0
5.1 - 5.5
5.6 - 6.0
6.1 - 6.5
6.6 - 7.0
7.1 - 7.5
> 7.5

Figure 24. Map of Direct Normal Irradiance (DNI) and Utility-Scale CSP Project Locations

3.2 Installed Project Prices (7 projects, 1,381 MW$_{AC}$)

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other CSP projects, totaling 1,381 MW$_{AC}$, that were commercially operational at the end of 2016 and larger than 5 MW$_{AC}$. Five of these seven projects feature parabolic trough technology (one of which has 6 hours of molten salt thermal storage capabilities), while the two most recently built projects use power tower technology (one project consisting of a total of 3 solar towers without long-term storage, the other featuring just one tower but with 10 hours of molten salt storage).

---

[55] DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position in the sky. The DNI data represent average irradiance from 1998-2009 (Perez 2012).

Figure 25 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2015),[56] and also compares their installed prices to the median installed price of PV (from Figure 8) in each year from 2010 through 2016. The small sample size makes it difficult to discern any trends. In 2014, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($\$5.25/W_{AC}$ vs. $\$6.31/W_{AC}$). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $\$6.95/W_{AC}$), while the 2014 power tower project was priced at the higher end of the range of the two trough projects built that same year. The most recent addition to our sample is the Crescent Dunes project, which faced a prolonged testing and commissioning phase that delayed commercial operation by roughly a year. The estimated cost of this project, which features 10 hours of molten salt storage, is the highest in our sample, at $\$8.98/W_{AC}$.

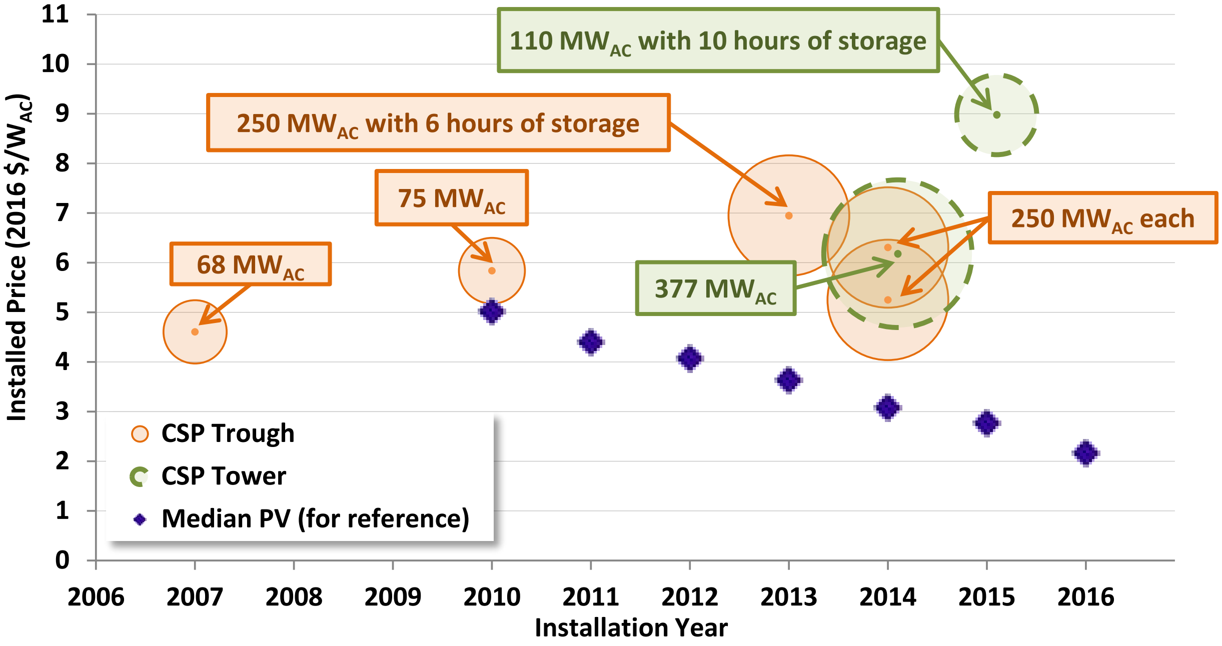


Figure 25. Installed Price of CSP Projects by Technology and Installation Year

Since 2007, CSP prices do not seem to have declined over time in the United States, which stands in stark contrast to the median PV prices included in the figure. Of course, the CSP sample is small, and features several different technologies and storage capabilities, which complicates comparisons.

---

[56] The installed CSP prices shown in Figure 25 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

3.3 Capacity Factors (13 projects, 1,654 MW_{AC})

Figure 26 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 26[57]) of our CSP project sample. The nine SEGS projects are grouped within the green and red shaded areas as indicated, rather than broken out individually. For comparison purposes, the average capacity factor in each calendar year from our sample of PV projects located in California, Nevada, and Arizona—i.e., the three states in which the CSP projects in our sample reside—are also shown.

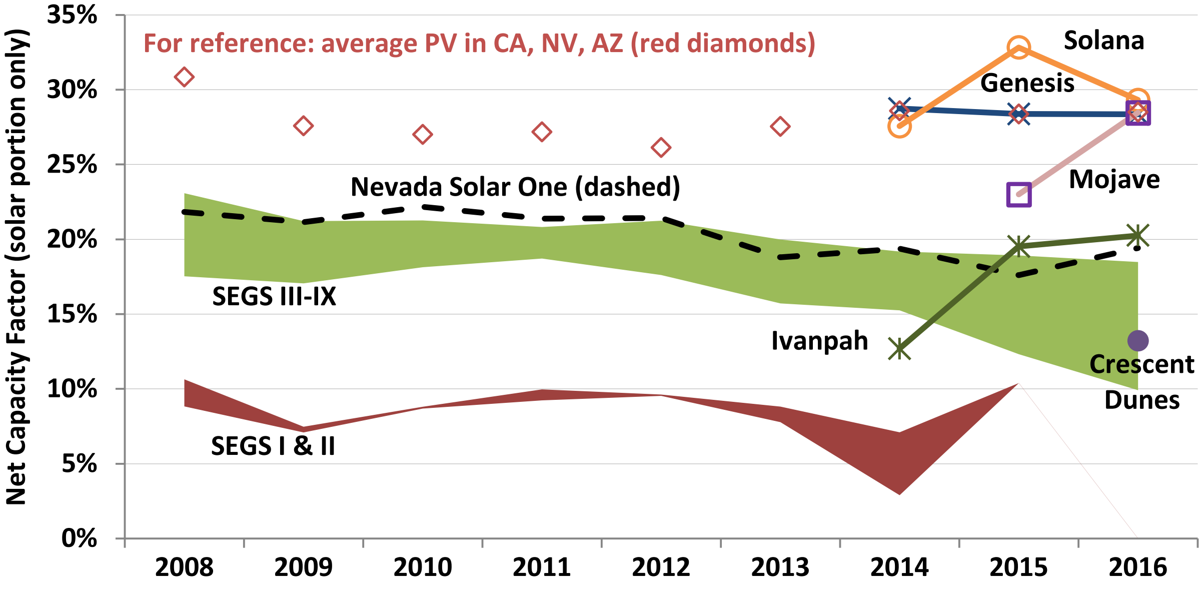


Figure 26. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

A few points are worth highlighting:

- The two "power tower" projects—Ivanpah and Crescent Dunes—experienced closures that negatively impacted performance in 2016. In the spring of 2016, misaligned heliostats caused a portion of Ivanpah's Unit 3 tower to catch on fire, requiring roughly one-third of the plant's capacity to come offline for more than a month. Then, in late-October 2016, Crescent Dunes was forced to shut down following the discovery of what was reportedly a small leak in one of the molten salt tanks used for thermal storage; the repair took more than eight months, during which time the plant did not operate (Brean 2017). As a result of these closures, 2016 capacity factors at both projects were significantly below long-term expectations of ~27% and ~50%, respectively.

---

[57] Many of these projects also use gas-fired turbines to supplement their output (e.g., during shoulder months, into the evening, or during cloudy weather). In the case of Nevada Solar One, for example, gas-fired generation has boosted historical capacity factors by twenty to forty basis points depending on the year (e.g., from 19.4% solar-only to 19.8% gas-included in 2016), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 190-370 basis points in 2016, depending on the project. The Ivanpah power tower project also burns gas primarily to keep its steam turbines sufficiently warm overnight and to generate the morning's first steam, both of which significantly shorten each day's ramp-up period; the amount of total generation attributable to burning gas at Ivanpah is limited to 5%, and has reportedly been under that threshold to date (Kraemer 2016).

- Solana—i.e., the 250 MW solar trough project with 6 hours of thermal storage—performed at a lower capacity factor than in 2015, and well below long-term expectations of >40%. This project too was reportedly hit by a brief closure following storm damage from a micro-burst on July 29, 2016, which was expected to reduce availability for several months thereafter (Stern 2016). More recently, two transformer fires reportedly cut output in half during the peak insolation months of July and August 2017 (Stern 2017), suggesting that performance goals may be missed again in 2017.
- Genesis (250 MW_{AC} trough with no storage) maintained its 2014 and 2015 capacity factors into 2016 (at 28.4%, right on expectations), while the slightly newer but otherwise very similar Mojave project (also a 250 MW_{AC} trough with no storage) improved significantly upon its 2015 performance, largely matching expectations (and Genesis) in 2016.
- Both of these newer trough projects without storage (Genesis and Mojave) performed significantly better in 2016 than the existing fleet of eight older trough projects (also without storage) in the sample, including the seven SEGS plants (SEGS III-IX, totaling 349 MW_{AC}) that have been operating in California for at least twenty-five years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[58]
- The Solana, Genesis, and (in 2016) Mojave projects have been able to match (or, in the case of Solana in 2015, exceed) the average capacity factor among utility-scale PV projects across California, Nevada, and Arizona. All other CSP projects shown in Figure 26 have exhibited significantly lower capacity factors.

Looking ahead, we'll continue to watch for improvements from Ivanpah (following the May 2016 fire and subsequent brief closure), Crescent Dunes (though not in 2017, as the late-2016 shut-down lasted throughout the first half of 2017), and Solana as they attempt to dial up performance to match pre-construction estimates.

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1,301 MW_{AC})

The PPA price sample for CSP projects includes six of the seven projects built since the turn of the century (the 75 MW_{AC} Martin trough project in Florida, which was built in 2010, is owned by a utility, and so does not have a PPA). Contract terms range from 20 to 30 years, with both a median and mean term of 25 years.

PPA prices from five of these six projects are shown in Figure 27 (along with the de-emphasized PV PPA price sample from utility-scale PV projects located in California, Nevada, and Arizona, for reference). The sixth, Nevada Solar One, is excluded in order to make the figure more readable, given that its PPA was executed in late-2002 (and later amended in 2005). Nevada Solar One's levelized PPA price of ~$193/MWh (in real 2016 dollars) is the highest in our sample, though not by much.

---

[58] One additional parabolic trough project—the 75 MW_{AC} Martin project in Florida—is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

Most of these CSP contracts appear to have been competitive with utility-scale PV projects in their home states at the time they were executed. Since then, however, PPA prices from utility-scale PV projects have declined significantly, and CSP has not been able to keep pace. As a result, there have been no new CSP PPAs executed in the United States since 2011, and a number of previously-executed CSP contracts have been either canceled or converted to PV technology.

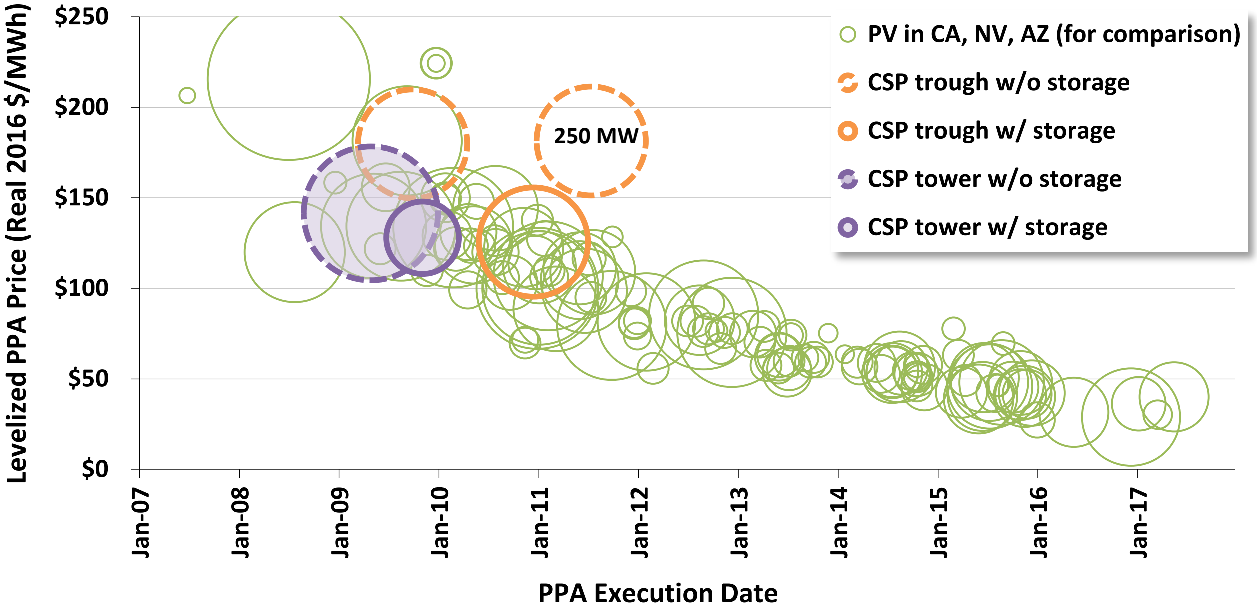


Figure 27. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

4. Conclusions and Future Outlook

This fifth edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since 2007-2009, relatively modest O&M costs, solid performance with improving capacity factors, and record-low PPA prices of around $30/MWh (levelized, in real 2016 dollars) in a few cases and under $50/MWh on average—even in areas outside of the traditional strongholds of California and the Southwest. Meanwhile, the other principal utility-scale solar technology, CSP, has also made strides in recent years—e.g., deploying several large projects featuring new trough and power tower technologies and demonstrating thermal storage capabilities—but has struggled to meet performance expectations in some cases, and is otherwise finding it difficult to compete in the United States with increasingly low-cost PV. As a result, there were no new CSP projects either online or under construction in 2016.

Looking ahead, December 2015's long-term extension of the 30% ITC through 2019 (along with the switch to a "start construction" rather than "placed in service" deadline), with a gradual phase down to 10% thereafter, should ensure continued momentum for the next few years. Data on the amount of utility-scale solar capacity in the development pipeline support this view, and also suggest a significant expansion of the industry—both in terms of volume and geographic distribution—in the coming years. For example, Figure 28 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2016.[59] Although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built[60]—as a result, these data should be interpreted with caution. That said, efforts have been made by the FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have, in previous years, clogged these queues, and despite its inherent imperfections, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development.

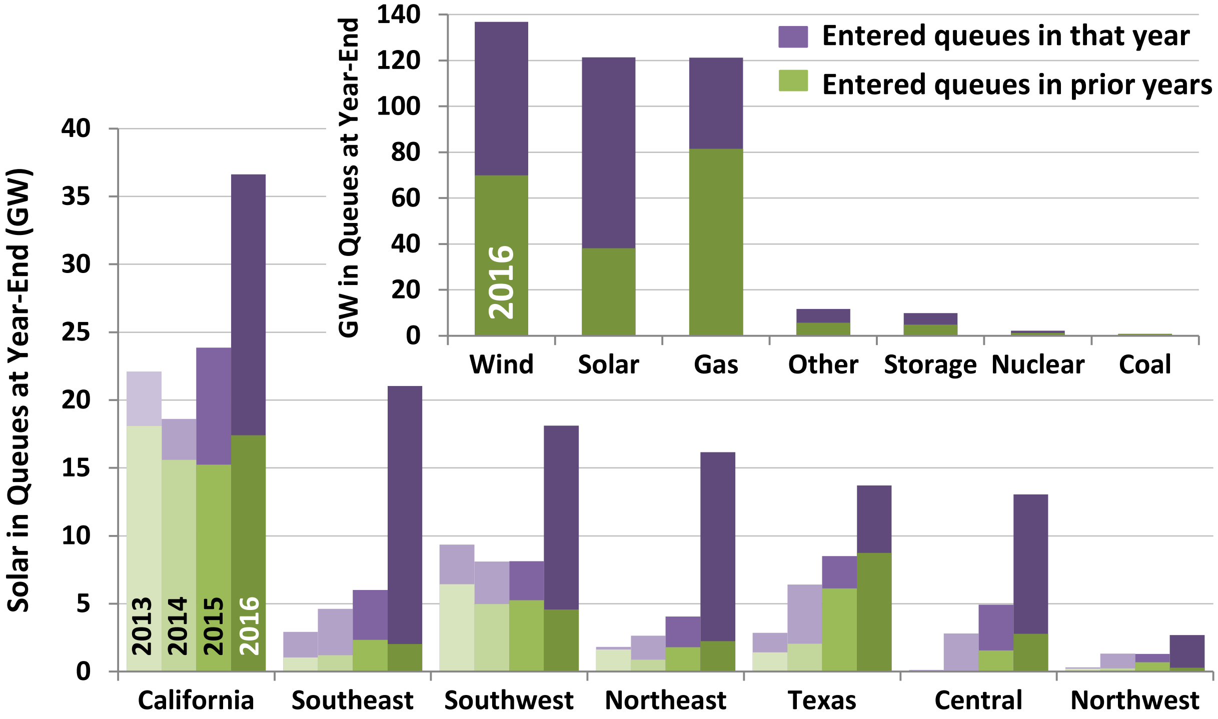
At the end of 2016, there were 121.4 GW of solar power capacity (of any type—e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report—***more than six times the installed utility-scale solar power capacity in our entire project population at that time.*** These

---

[59] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of ~85% of the U.S. total. Figure 28 only includes projects that were active in the queue at the end of 2016 but that had not yet been built; suspended projects are not included.

[60] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences net out.

121.4 GW—83.3 GW of which first entered the queues in 2016—represented 30% of all generating capacity within these selected queues at the time, just behind wind power at 34% and essentially tied with natural gas, also at 30% (see Figure 28 inset). The end-of-2016 solar total is also 64.6 GW higher than the 56.8 GW of solar that were in the queues at the end of 2015, demonstrating that the solar pipeline was more than replenished in 2016, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2016.



Source: Exeter Associates review of interconnection queue data

Figure 28. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 28 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides (as well as how that composition has changed going back to 2013). Perhaps not surprisingly (given the map of solar resource and PV project location shown in Figure 3 earlier), 45% of the total solar capacity in the queues at the end of 2016 is within California (30%) and the Southwest region (15%). This combined 45% is down from 56% at the end of 2015, 60% at the end of 2014, and 80% at the end of 2013, however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest. The Southeast, for example, surpassed the Southwest in terms of solar in the queues at the end of 2016, and the Northeast and Central regions, along with Texas, all showed strong growth in solar project pipelines in 2016.

Though not all of the 121.4 GW of planned solar projects represented in Figure 28 will ultimately be built, as shown earlier in Figure 1, analysts expect strong growth in new installations averaging 8.6 GW per year over the next six years, driven in part by the long-term extension of the 30% ITC, coupled with utility-scale PV's declining costs. Of course, accompanying all of this new solar capacity will be substantial amounts of new cost, price, and performance data, which we hope to collect and analyze in future editions of this report.

References

Data Sources

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources), broken out by data set:

Technology Trends: Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), interviews with project developers and owners, trade press articles

Installed Prices: Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL

O&M Costs: FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors: FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices: FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

In addition, the individual reference documents listed below provided additional data and/or helped to inform the analysis.

Literature Sources

Advanced Energy. 2014. "DC Loading of AE TX Inverters." http://solarenergy.advanced-energy.com/upload/File/Application%20Notes/ENG-DCLoadingTX-260-02_Web.pdf.

Barbose, Galen, and Naim Darghouth. 2017. "Tracking the Sun X: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States." Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL). trackingthesun.lbl.gov.

Berg, Josefin, Camron Barati, and Sam Wilkinson. 2017. "Suniva Petition Puts United States PV Demand at Risk and Shakes up Global Supply Chain." London, UK: IHS Markit. https://technology.ihs.com/592016/suniva-petition-puts-united-states-pv-demand-at-risk-and-shakes-up-global-supply-chain.

BNEF. 2017. "Tax Equity Update: 2017." Bloomberg New Energy Finance (BNEF).

Bolinger, Mark. 2013. "Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices." LBNL-6103E. Berkeley, CA: Lawrence Berkeley National Laboratory. http://emp.lbl.gov/publications/revisiting-long-term-hedge-value-wind-power-era-low-natural-gas-prices.

———. 2014. “An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives.” LBNL-6350E. Berkeley, CA: Lawrence Berkeley National Laboratory. http://emp.lbl.gov/publications/analysis-costs-benefits-and-implications-different-approaches-capturing-value-renewable.

———. 2017. “Using Probability of Exceedance to Compare the Resource Risk of Renewable and Gas-Fired Generation.” Technical Report LBNL-1007269. Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL).

Bolinger, Mark, and Joachim Seel. 2015. “Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.” LBNL-1000917. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/utility-scale-solar-2014-empirical.

Bolinger, Mark, Joachim Seel, and Manfei Wu. 2016. “Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltaic Projects in the United States.” Technical Report LBNL-1004374. Berkeley, CA: Lawrence Berkeley National Laboratory (LBNL).

Brean, H. 2017. “Nevada Solar Plant Back Online after Eight-Month Outage.” *Las Vegas Review-Journal*, July 21. https://www.reviewjournal.com/business/energy/nevada-solar-plant-back-online-after-eight-month-outage/.

Bromley, Hugh, and Nathan Serota. 2016. “American PV Market Outlook, H2 2016.” Bloomberg New Energy Finance.

Cole, Wesley, Trieu Mai, Jeffrey Logan, Daniel Steinberg, James McCall, James Richard, Benjamin Sigrin, and Gian Porro. 2016. “2016 Annual Technology Baseline.” Technical Report NREL/TP-6A20-66939. Golden, CO: National Renewable Energy Laboratory (NREL). http://www.nrel.gov/analysis/data_tech_baseline.html.

Denholm, Paul, Josh Eichman, and Robert Margolis. 2017. “Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants.” NREL/TP-6A20-68737. Golden, CO: National Renewable Energy Laboratory (NREL). https://www.nrel.gov/docs/fy17osti/68737.pdf.

Dierauf, Timothy, Aaron Growitz, Sarah Kurtz, Jose Luis Becerra Cruz, Evan Riley, and Clifford Hansen. 2013. “Weather-Corrected Performance Ratio.” NREL/TP-5200-57991. Golden, CO: National Renewable Energy Laboratory (NREL). http://www.nrel.gov/docs/fy13osti/57991.pdf.

Energy Information Administration (EIA). 2017. “Annual Energy Outlook 2017.” Washington D.C. https://www.eia.gov/outlooks/aeo/.

Fiorelli, J, and M Zuercher - Martinson. 2013. “Array Oversizing.” White Paper. Solectria Renewables.

First Solar. 2016. “Series 4 - Up to 7.5% More Energy in Real World Conditions.” *First Solar PV Modules*. http://www.firstsolar.com/Modules/Series-4.

Fu, Ran, David Feldman, and Robert Margolis. 2017. “U.S. Solar Photovoltaic System Cost Benchmark Q1 2017.” NREL/TP-6A20-68925. Golden, CO: National Renewable Energy Laboratory (NREL). https://www.nrel.gov/docs/fy17osti/68925.pdf.

Fu, Ran, Ted James, Donald Chung, Douglas Gagne, Anthony Lopez, and Aron Dobos. 2015. “Economic Competitiveness of U.S. Utility-Scale Photovoltaics Systems: Regional Cost Modeling of Installed Cost ($/W) and LCOE ($/kWh).” In *IEEE PVSC 42 - Sub-Area 9.5 Power Electronics, Energy Storage and Other BOS Components*. New Orleans.

GTM Research, and SEIA. 2017. “U.S. Solar Market Insight Report: 2016 Year in Review.” Washington D.C.: Solar Energy Industry Association.

ICE. 2017. “ICE Benchmark Administration.” Intercontinental Exchange (ICE). https://www.theice.com/iba.

Kraemer, Susan. 2016. “Newly Released Data Indicates Ivanpah Gas Is Under 5%.” *Clean Technica*, April 25. http://cleantechnica.com/2016/04/25/newly-released-data-indicates-ivanpah-gas-5-percent/.

Lazard. 2016. “Levelized Cost of Energy Analysis 10.0.” https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/.

Maloney, P. 2017. “How Can Tucson Electric Get Solar + Storage for 4.5¢/kWh?” *Utility Dive*, May 30. http://www.utilitydive.com/news/how-can-tucson-electric-get-solar-storage-for-45kwh/443715/.

Mills, Andrew D., and Ryan H. Wiser. 2013. “Changes in the Economic Value of Photovoltaic Generation at High Penetration Levels: A Pilot Case Study of California.” *IEEE Journal of Photovoltaics* 3 (4): 1394–1402. doi:10.1109/JPHOTOV.2013.2263984.

NextEra Energy. 2017. “2017 Investor Conference Presentation.” June 22. http://www.investor.nexteraenergy.com/phoenix.zhtml?c=88486&p=irol-presentations.

Perez, Richard. 2012. “Solar Direct Normal and Global Horizontal Irradiance Data 1998-2009 with 10km Resolution (WGS_1984).” State University of New York/Albany , National Renewable Energy Laboratory (NREL). http://www.nrel.gov/gis/data_solar.html.

Stern, Ray. 2016. “Solana Solar Plant’s Poor Performance Gets Worse After July Microburst Damage.” *Phoenix New Times*, September 22. http://www.phoenixnewtimes.com/news/solana-solar-plants-poor-performance-gets-worse-after-july-microburst-damage-8671474.

———. 2017. “Dark Clouds—Transformer Fires and Air Pollution—Continue to Follow Solana Power Plant.” *Phoenix New Times*, August 30. http://www.phoenixnewtimes.com/news/arizonas-solana-solar-plant-transformer-fires-more-air-pollution-9640548.

Vaisala. 2013. “Solar Variance from Average: June-August 2013.”

———. 2014. “Summer 2014 Solar Performance Map.” http://www.vaisala.com/Vaisala%20Documents/Vaisala%20News%20Articles/Misc/2014%20Solar%20Performance%20Map.pdf.

———. 2015. “2014 US Solar Performance Maps.” http://www.vaisala.com/Vaisala%20Documents/Vaisala%20News%20Articles/Misc/2014_US_Solar_Performance_report.pdf.

———. 2016. “2015 US Solar Performance Maps.” http://www.vaisala.com/Vaisala%20Documents/Vaisala%20News%20Articles/Misc/Vaisala_2015_US_Solar_Performance_Maps_Summary.pdf.

———. 2017. “2016 US Solar Performance Maps.” http://www.vaisala.com/Vaisala%20Documents/Vaisala%20News%20Articles/Misc/2016_US_SolarPerformance_Q1-Q4.pdf.

ViZn Energy. 2017. “Solar Nights: Utility Scale Solar and Wind Power for Less than Coal.” https://www.viznenergy.com/webinars/.

Appendix

Total PV Population

State	Size Range (MW_{AC})	Year Range	2016 Sample		Total Population	
			# of Projects	Total MW_{AC}	# of Projects	Total MW_{AC}
AL	75 - 75	2016 - 2016	1	75	1	75
AR	13 - 13	2015 - 2015	0	0	1	13
AZ	5 - 290	2011 - 2016	7	381	37	1,491
CA	5 - 586	2009 - 2016	49	2,978	157	8,040
CO	5 - 120	2007 - 2016	7	225	13	368
DE	10 - 12	2011 - 2012	0	0	2	22
FL	5 - 75	2009 - 2016	4	229	9	288
GA	6 - 146	2013 - 2016	14	726	23	956
HI	6 - 12	2012 - 2016	1	7	4	36
ID	40 - 80	2016 - 2016	2	120	2	120
IL	8 - 20	2010 - 2012	0	0	2	28
IN	5 - 10	2013 - 2016	3	16	12	92
KY	10 - 10	2016 - 2016	1	10	1	10
MA	6 - 15	2014 - 2016	1	15	3	35
MD	6 - 20	2012 - 2016	3	31	7	80
MN	7 - 100	2016 - 2016	2	107	2	107
NC	7 - 81	2010 - 2016	9	349	32	899
NJ	5 - 18	2010 - 2016	6	46	26	227
NM	5 - 70	2010 - 2016	3	165	25	439
NV	10 - 255	2007 - 2016	6	723	20	1,396
NY	10 - 32	2011 - 2016	1	10	2	41
OH	8 - 10	2010 - 2011	0	0	2	18
OR	6 - 10	2016 - 2016	7	63	7	63
PA	10 - 10	2012 - 2012	0	0	1	10
SC	7 - 7	2016 - 2016	1	7	1	7
TN	8 - 16	2012 - 2016	2	24	5	63
TX	6 - 158	2010 - 2016	2	264	14	569
UT	20 - 80	2015 - 2016	10	680	12	810
VA	17 - 80	2016 - 2016	4	137	4	137
Total	**5 - 586**	**2007 - 2016**	**146**	**7,385**	**427**	**16,439**

Total CSP Population

State	Size Range (MW_{AC})	Year Range	2016 Sample		Total Population	
			# of Projects	Total MW_{AC}	# of Projects	Total MW_{AC}
AZ	250	2013	0	0	1	250
CA	34 - 377	1986 - 2014	0	0	10	1,234
FL	75	2010	0	0	1	75
NV	69 - 110	2007 - 2015	0	0	2	179
Total	**34 - 377**	**1986 - 2015**	**0**	**0**	**14**	**1,737**

Key Report Contacts

Lawrence Berkeley National Laboratory, Electricity Markets and Policy Group:

Mark Bolinger
603-795-4937 MABolinger@lbl.gov

Joachim Seel
510-486-5087 JSeel@lbl.gov

Download the Report

Utility-Scale Solar Project Page with data files and interactive visualizations:

https://utilityscalesolar.lbl.gov

All EMP renewable energy publications:

https://emp.lbl.gov/reports/re

QR Code to all EMP solar publications:

Acknowledgments

The authors thank Elaine Ulrich, Odette Mucha, Ammar Qusaibaty, Becca Jones-Albertus, and Charlie Gay of the U.S. Department of Energy's Solar Energy Technologies Office for their support of this work. Thanks also to the following individuals for reviewing earlier drafts of this report: Christopher Namovicz, Cara Marcy, and Manussawee Sukunta (U.S. Energy Information Administration); Brad Rockwell (Kaua'i Island Utility Cooperative); John Miller (Black & Veatch); Ryan Wiser (Lawrence Berkeley National Laboratory); Dirk Weiss (First Solar); and Ran Fu (National Renewable Energy Laboratory). Of course, any remaining errors or omissions are the sole responsibility of the authors.

Cover photos courtesy of Sempra U.S. Gas & Power, NREL, and BrightSource Limitless.

This manuscript has been authored by an author at Lawrence Berkeley National Laboratory under Contract No. DE-AC02-05CH11231 with the U.S. Department of Energy. The U.S. Government retains, and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains, a non-exclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this manuscript, or allow others to do so, for U.S. Government purposes.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

ELECTRICITY MARKETS & POLICY GROUP

BERKELEY LAB
LAWRENCE BERKELEY NATIONAL LABORATORY

Powered by SunShot
U.S. Department of Energy